Simulation Study on Effect of Slug Size In Foam-Assisted Water Alternating Gas (FAWAG-CO2) Injection with Presence of Asphaltene In Light Oil Reservoir

by

WAN AFIQ FARHAN BIN CHE HAMAT

13874

Dissertation submitted in partial fulfilment of
the requirement for the
Bachelor of Engineering (Hons)
(Petroleum)

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Universiti Teknologi PETRONAS

Bandar Seri Iskandar

31750 Tronoh

Perak Darul Ridzuan

CERTIFICATION OF APPROVAL

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Approved by,

……..
(Ali F. Mangi Alta'ee)

UNIVERSITI TEKNOLOGI PETRONAS
TRONOH, PERAK
MAY 2014

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

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WAN AFIQ FARHAN CHE HAMAT

ABSTRACT

Enhanced Oil Recovery (EOR) is an essential method in extracting residual oil after waterflooding. Around 40% of recovery from primary until secondary for a typical oil field around the world which drives many company to implement EOR to squeeze more oil. Foam-Assisted Water Alternating Gas (FAWAG- CO_2) is one of the improved techniques of Water Alternating Gas (WAG-CO_2) in enhancing gas mobility control and preventing viscous fingering and gravity overriding which could cause early gas breakthrough. The situation becomes more complex with presence of asphaltene in light crude oil reservoir. Asphaltene precipitation, flocculation and deposition can cause serious problems especially in production stage whereby it can adversely affect the economy of producing oilfield.

This project aims to study the impact of asphaltene precipitation and minimize the precipitation by controlling FAWAG-CO_2 injection parameters; pore volume ratio, injection rate and concentration of surfactant. Simulation studies were performed with both WAG and FAWAG injection to study effect of asphaltene deposition.

The simulation study results concluded that recovery in FAWAG injection is higher than WAG injection in both with and without asphaltene presence. FAWAG with asphaltene is higher than FAWAG without asphaltene. Ratio of 2:1 is optimum for both FAWAG-CO_2 and WAG- CO_2 with and without asphaltene presence. For surfactant concentration, the higher surfactant concentration, the higher the recovery factor until it reached optimum concentration. Higher concentration than optimum will result in lower recovery due to clogged pore throat as effect of adsorption of surfactant.

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CHAPTER 1

INTRODUCTION

1.1 PROJECT BACKGROUND

With nowadays advancement in technology, petroleum has become the biggest source of energy generation for industrialized countries and in developing countries. However with increasing global demand for petroleum, it requires efficient techniques for tertiary recovery of petroleum residual to ensure maximum recovery of petroleum before it begins abandonment stage. Basically, there are three stages of hydrocarbon recovery which are primary, secondary and tertiary. Secondary and tertiary recovery usually called Improved Oil Recovery (IOR) and tertiary recovery alone is known as Enhanced Oil Recovery (EOR).

In the primary recovery stage, the production of hydrocarbon depends upon the energy from reservoir itself. The energy can be derived from drive mechanism that the reservoir has which either water drive, gas cap drive, gravity drive, compaction drive or solution gas drive. The drive mechanism can be either solely from single drive or combination. After the reservoir pressure depleted and production of hydrocarbon decreased, secondary recovery takes place by placing injectors inside the reservoir which to maintain the reservoir pressure and to squeeze hydrocarbon out from reservoir. One of secondary recovery example is waterflooding. Prior to waterflooding, injector wells are drilled in a pattern to displace the remaining oil. During waterflooding, water displaces most at the bottommost and least at the topmost due to gravity segregation until water breakthrough. After water production reached 80 percent of total fluid production, the waterflooding stops and EOR starts.

Enhanced Oil Recovery (EOR) or tertiary recovery is an essential stage in improving total production. Approximately 40 percent of global average recovery factor for a typical oil field from primary recovery until secondary recovery. The large amount of hydrocarbon left behind is the main driver behind EOR schemes that have been practiced around the world. Although the cost to cover EOR process is quite expensive, EOR can improve the production up to 75 percent recovery. The main objective of EOR process is to change the properties of hydrocarbon such surface tension, viscosities, and pH value which illuminate further EOR process from secondary recovery method. There are three main type of EOR process which are chemical flooding, gas injection, and thermal recovery.

Carbon dioxide (CO_2) injection is one of efficacious Enhanced Oil Recovery (EOR) methods to improve oil recovery, however it has potential to cause asphaltene precipitation. As gas is injected into the reservoir, the miscibility of the carbon dioxide will disrupt asphaltene-resin ratio and cause asphaltene precipitation (Kokal & Sayegh, 1995). Precipitation of asphaltene could plug near-wellbore formation and cause reduced recovery efficiency and formation damage. It is also may precipitate at surface facilities especially in well tubing, well head and separator which can cause high maintenance cost problem.

Water Alternating Gas (WAG) is one of EOR process which employs gas injection in the method. Gas can be injected by through miscible or immiscible flooding. By injecting immiscible gases into the reservoir, the gases can expand and push hydrocarbon through the reservoir. While miscible gases dissolve within the hydrocarbon increasing the flow by reducing the hydrocarbon viscosity.

Foam Assisted Water Alternating Gas (FAWAG) injection is an improvement to Water Alternating Gas (WAG) process. In the application of WAG, injected gas tends to rise to the top of the reservoir owing to gravity segregation. As a result, the sweep efficiency decreases (Al-Mossawy *et al*, 2011). The gas also can seep through high permeability zone which can cause early gas breakthrough. To avoid this situation, foaming agent or surfactant is introduced during water injection to increase gas mobility control (Saleem *et al*, 2012) which improves gas sweep efficiency by increasing effective viscosity and reduce the relative permeability of the injected gas (Al-Mossawy *et al*, 2011).

1.2 PROBLEM STATEMENT

Asphaltene precipitation is a serious problem in production of light oil reservoir. The precipitation of asphaltene may cause formation damage, recovery reduction, problem in well inflow and tubing performance, and wellbore plugging. Asphaltene can be removed via reservoir condition manipulation, mechanical cleaning, or chemical cleaning. However, the cost of cleaning the asphaltene is very expensive that can be adversely affect the production until it becomes economically unfeasible (Kokal & Sayegh, 1995). Due to this, most of studies are focused on to minimize the effect of asphaltene precipitation by controlling injection condition such as FAWAG ratio, injection pressure, and concentration of surfactant.

1.2.1 Problem Identification

Only 5 to 10 percent incremental recovery of total original oil in-place (OOIP) is obtained with current WAG and FAWAG process due to various operational problem and escalating operational cost. The total incremental recovery becomes lesser when asphaltene is involved. Thus to minimize the effect of asphaltene precipitation and deposition, injection parameters are controlled to determine optimum injection rate, surfactant concentration and PV ratio.

1.2.2 Significant of the Project

The findings from this research are significant in determining effect FAWAG (CO_2) injection on asphaltene precipitation with different concentrations of surfactant which may increase mobility control, hence lead to higher sweep efficiency, lower asphaltene precipitation and higher oil recovery. This research also focuses on finding optimum injection pressure, water salinity, and FAWAG (CO_2) ratio which can minimize the precipitation effect. Permeability and porosity reduction and wettability measurement will be performed to justify the results in controlling parameters of FAWAG (CO_2).

1.3 RESEARCH OBJECTIVES

This project aims to accomplish the following key objectives:

1. To determine the effect of FAWAG technique towards asphaltene deposition in light oil
2. To investigate the optimum FAWAG parameter for maximum oil recovery
3. To determine the optimum concentration of surfactant on oil recovery and cost analysis of injected surfactant

1.4 SCOPE OF STUDY

The research will be performed by using a compositional reservoir simulator. Fluid and reservoir model for light oil reservoirs will be obtained from actual core sample. Two reservoir models will be established to run simulation of FAWAG-CO_2 before it proceeds to optimization stage which to simulate different injection pressures surfactant with different concentrations, PV ratio. There will be no involvement of lab experimentation in this project.

CHAPTER 2

LITERATURE REVIEW

2.1 ENHANCED OIL RECOVERY (EOR)

Enhanced Oil Recovery (EOR) is defined as processes that could increase amount of oil extraction from a reservoir, by injecting a liquid (e.g. surfactant, water, steam) or gas (e.g. carbon dioxide, nitrogen) (Green & Willhite, 1998). The main goal of EOR is to alter hydrocarbon properties (e.g. viscosity, surface tension, etcetera) in order to extract residual oil in the reservoir. Carbon dioxide (CO_2) injection is one of the common practice around the world and it has been used in the EOR process. According to Yongmao *et al*. (2004), CO_2 injection can prolong life cycle of near-depletion light and medium oil fields by 15 to 20 years and has potential to recover 15% to 25% of the original oil in place.

2.2 CO_2 INJECTION

CO_2 injection is adopted due to cheap operating cost and taxes exclusion which will benefit the overall cost of project. There are two type of CO_2 injection process which are miscible and immiscible flooding. CO_2 miscible injection improves oil recovery by reduction of oil viscosity, oil swelling, reducing residual oil saturation to near zero and dissolved-gas drive (Sima *et al*., 2011; Ghedan, 2009, Srivastava *et al*. 1997; Al-Qasim, 2011, Martin & Taber, 1992). During miscible process of CO_2, it reduces low interface tension between oil and gas phase which enable the oil to flow easily. However, miscibility of CO_2 with crude oil will cause composition alteration, and modification to asphaltene resin ratio which will result in precipitation of asphaltenes (Ghedan, 2009; Kokal & Sayegh, 1995).

2.3 WATER ALTERNATING GAS (WAG)

During gas injection, the gas inclines to displace the oil, however it tends to cause instability in displacement front due to significant different magnitudes of displacing fluid viscosity with displaced fluid viscosity (Hun, 2012; Aris, 2013) which can cause viscous fingering which will cause undesired early breakthrough. To mitigate viscous fingering event, water alternating gas (WAG) is introduced (Green & Willhite, 1998). WAG injection has been used as gas mobility control method which shown improvement in sweep efficiency and higher oil recovery (Ghedan, 2009; Green & Willhite, 1998). The existence of water in WAG injection is somehow believed reduce the asphaltene flocculation. (Al-Qasim, 2011; Srivasta *et al*., 1997). WAG injection is one of EOR methods which involves three-phase fluid flow. During WAG injection, water and gas is injected into the reservoir and usage of water is initially proposed to improve sweep efficiency of gas by controlling gas mobility ratio and stabilize the water front (Christensen *et al.*, 2001). WAG process is a cyclic method of injecting alternating cycles of CO2 followed by water and repeating this process over a number of cycles which shown improvement in sweep efficiency and higher oil recovery (Ghedan, 2009; Green & Willhite, 1998). With water gaining mobility control over gas which it will prolong the field life cycle and improve the oil recovery (Martin *et al.,* 2006). Other than improving the mobility control, other advantages of WAG also need to be highlighted. Compositional change during cycles of CO2 and water injection may result in additional recovery and altered the fluid viscosities and densities (Christensen et al, 2001).

WAG displacement is contributed by three main factors which are Ev,vertical sweep, Eh, horizontal sweep, and Em, microscopic displacement efficiency. Vertical and horizontal sweep are also known as macroscopic displacement efficiency. Oil recovery can described by the formula below:

$$Rf = Ev\ x\ Eh\ x\ Em$$

Horizontal displacement efficiency is strongly influenced by the stability of water front which defined by the mobility of the fluids. The mobility ratio can depicted as below:

$$M = \frac{k_{rg} \,/\, \mu_g}{k_{ro} \,/\, \mu_o}$$

Where k_{rg} and k_{ro} are the relative permeabilities of gas and oil and μ_g and μ_o are viscosities for gas and oil. If obtained mobility ratio is unfavorable, it will cause early gas breakthrough (Christensen et al, 2001). Additional gas injection will flow through less resistance pathway which created by the prior gas breakthrough eventually decreasing the sweep efficiency. On contrary, according to Attanucci (1993) gas early breakthrough is not only caused by mobility ratio but also by high permeability layer in heterogeneous reservoirs. In general, mobility ratio is preferable if the ratio is less than 1.

In addition, the presence of water also reduces oil/gas contact which causes the miscibility of CO_2 harder to achieve. The presence of high permeability zone or thief zone and gravity segregation will further reduce the efficiency of WAG injection (Safazadeh *et al*., 2011).

2.4 FOAM-ASSISTED WATER ALTERNATING GAS (FAWAG)

Surfactant flooding is first introduced by Lawson & Reisberg (1980) with means for mobility control. Foam Assisted Water Alternating Gas (FAWAG) is an EOR method for reservoirs depleted by waterflooding. During injection of FAWAG process, surfactant and gas is injected into reservoir alternately by means of several cycles. The purpose of surfactant is to lower oil-water interfacial tension which then it will promote the oil-water miscibility and reduces the saturation of oil. The preferred method is to inject relatively concentrated surfactant with injection of less than 1 pore volume slug size followed by CO2 injection (Lawson & Reisberg, 1980).

Basically, the energy required to form a foam is inversely proportional to the interfacial tension. Introducing surfactant will help to reduce the interfacial tension which will result in low energy required to create foam. As surfactant is injected into the reservoir the surface of water will become elastic with means it can withstand being bumped, squeezed or deformed (Dalton & Eastoe, 2000).

Another advantages of FAWAG is gravity segregation and high permeability zones can be solved by using the technique. Due to density difference, gas tends to rise to upper layer of reservoir and contact with surfactant and forms as foam. Surfactant is introduced in the process which is believed will increase gas mobility control (Saleem *et al*, 2012) by lowering the relative permeability and elevating effective viscosity of the injected gas (Al-Mossawy *et al*, 2011). The more gas travels upper part of reservoir, increasing number of foam will be generated. Foam will act as the trapping agent for gas which as foam layer is formed by time, it will act as wall to prevent gas from rises to upper part, and improve oil displacement process. While for high permeability zone case, foam will prevent gas from entering thief zone and diverts the gas to low permeable zones.

2.5 ASPHALTENE

Asphaltene is a complex molecules that insoluble in a low molecular weight n-alkanes that has surface tension lower than 25 dynes/cm, soluble in benzene, non-volatile, and polar. It is a fraction that separated from crude oil when it is contacted with hydrocarbon solvents such as n-heptane (Speight, 1999). It has no definite melting point (Kokal & Sayegh, 1995).

Precipitation of asphaltene can cause a great impact to reservoir and production. Problem such as reduction of permeability and porosity, changes of formation wettability, formation plugging, and fouling of surface facility such as well tubing and separator (Ghedan, 2009; Srivastava *et al*., 1997)

Source of asphaltene; depth of burial, sulphur content, and API gravity, varies with amount of asphaltene in a specific reservoir (Kokal & Sayegh, 1995). However, the problem pertaining precipitation of asphaltene is not defined by amount of it, but asphaltene stability (Kokal & Sayegh, 1995).

Asphaltene precipitation can be comprised of three processes. At first, precipitation happens at small solid particles formed out of solution. Then, the small particles clump together and become bigger. Lastly, the clump flocculates until liquid can no longer support it and deposit on surface (Alian, Omar, Alta'ee & Hani, 2011).

2.6 FACTOR AFFECTING ASPHALTENE DEPOSITION

Asphaltene is stabilized by resin, under colloidal state which remains in thermodynamic equilibrium at normal condition. Deposition of asphaltene is mainly depend upon properties of asphaltene itself and properties of fraction of crude oil (Ali & Shuker, 2012) which can cause severe problem to reservoir and production includes porosity reduction, wellbore plugging, permeability reduction (Ghedan, 2009; Srivastava *et al*., 1997). Factors such as alteration of temperature and pressure, flow regime, chemical composition, electro kinetic effect, and asphaltene and resin content can affect the asphaltene stability. The reservoir temperature is believed to have lesser effect on asphaltene precipitation compared to reservoir composition and pressure (Kokal & Sayegh, 1995; Hammani *et al*., 2000; Oskui & Abuhaimed, 2009). Operation such as phase separation, gas injection, incompatible chemicals and mixing of crude stream can alter the composition of surrounding fluid and affect asphaltene stability. In case of light oil reservoir, the solubility of asphaltene is low which makes it unstable and easy to precipitate (Sima *et al*., 2011). The main contributors towards asphaltene deposition is change in pressure, temperature and composition of fluid.

2.6.1 Change in Pressure

Change in pressure by fluid injection may alter the equilibrium state of reservoir fluid that may lead to precipitation of asphaltene. Pressure at which precipitation of asphaltene begins at constant temperature in live reservoir fluid is called asphaltene onset pressure (AOP). Lower asphaltene solubility is noted with lower reservoir pressure (Verdier *et al*., 2005; Sima *et al*, 2011). When pressure is decreasing from at higher point from bubble point pressure, the density of oil is reduced and the molecular mass increased (Hun, 2012). At bubble point pressure, minimum asphaltene solubility is occurred which there is the highest difference in molecular mass between bulk oil and asphaltene which favor in asphaltene precipitation (Hun, 2012; Hammani *et al*, 2000; Oskui & Abuhaimed, 2009). With increasing pressure drop in lighter hydrocarbon, the solubility between resin and asphaltene decreases, which result in precipitation of asphaltene (Alta'ee *et al*., 2010; Kokal & Sayegh, 1995; Hun, 2012; Mohammed *et al*., 1998).

2.6.2 Change in Temperature

According to the studies done by Moin *et al*. (2003), asphaltene stability become less stable with decreasing temperature due to reduction of solvency power of oil (energy distinction between crude oil molecules and asphaltene especially high aromatic oils). However, in the presence of CO_2, asphaltene is more stable although with reduction of temperature (Verdier *et al*., 2005) due to thermal expansion of solvent (CO_2) . Alteration of temperature may cause changes in resin and maltenes solubility (Hun, 2012) and precipitation of paraffin can trap some asphaltene during solidification (Verdier *et al*., 2005; Mohammed *et al*., 1998).

2.6.3 Change in Composition of Fluid

Resin-asphaltene solubility and phase equilibrium in crude oil can be altered in compound is added (Ghedan, 2009; Kokal & Sayegh, 1995; Sima *et al*., 2011; Hun, 2012). Injection of gas into reservoir may reduce the ratio of resin-asphaltene (Mohammed *et al*., 1998). Asphaltene will precipitate if the amount of resin is insufficient to coat asphaltene (Hun, 2012). Most miscible solvent have the capacity to induce asphaltene instability. The most effective asphaltene precipitant is CO_2 followed by alkanes (Gholoum *et al.*, 2003; Shedid & Zekri, 2004).

CHAPTER 3

METHODOLOGY

3.1 RESEARCH METHODOLOGY

This section consists of project analysis which involves data gathering from literature review, experimental analysis, and simulation work. A lot of research on asphaltene precipitation, flocculation and deposition that caused by CO2 injection have been studies. Author also read on how light oil reservoir has a high potential to have asphaltene precipitation which can cause wettability alteration, surface equipment damages, and formation damage. The author also focused on surfactant and salinity flooding which later on will be applied in the simulation. Apart of the research, consist of reading manual and exploring for the software which will be used in the simulation.

Some of the planned processes for the project are as follow:

i. Literature review
ii. Software exploration

3.2 SOFTWARE REQUIRED

Numerical simulators from Computer Modelling Group (CMG) will be used by author which are Builder, Winprop, GEM, and STARS.

i. Builder – Application to build reservoir model by designing the reservoir properties, rock-fluid interaction, and others.

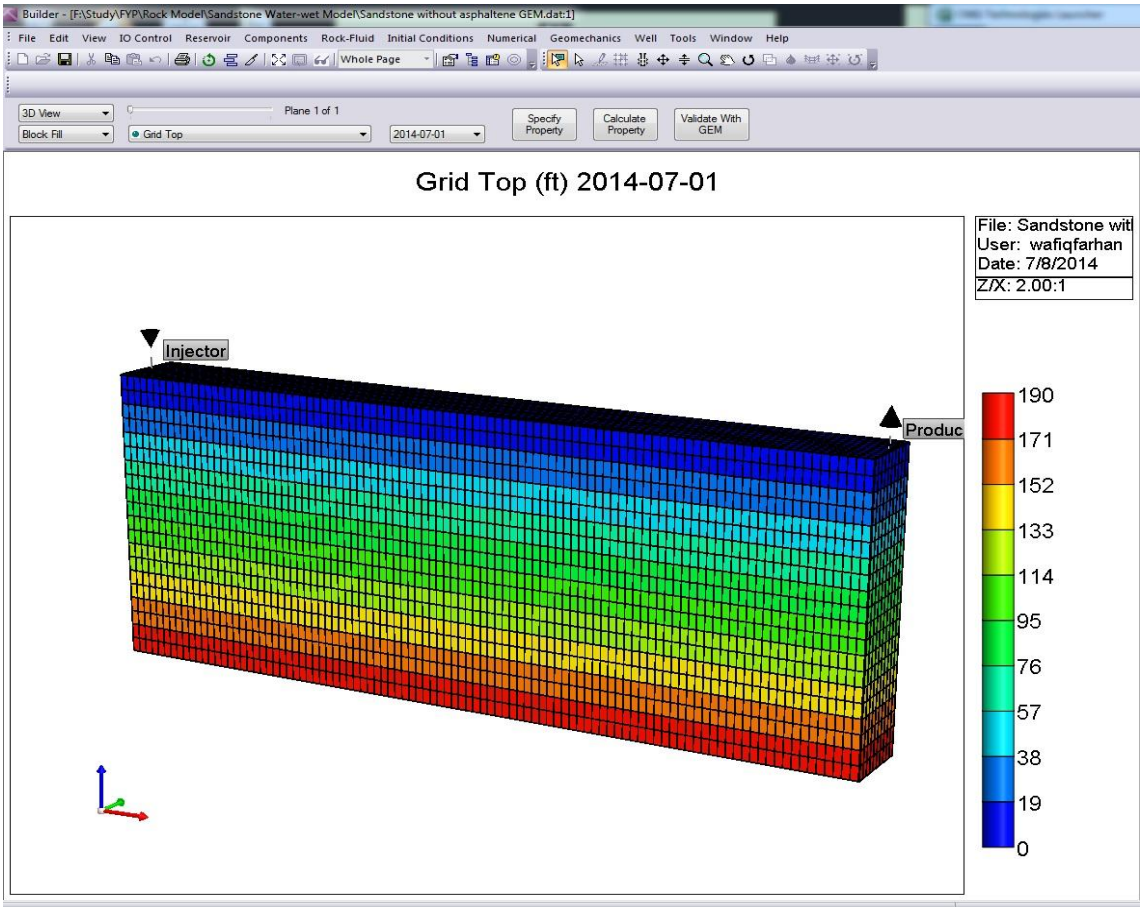


Figure 1: Builder - Simulate the reservoir (example)

ii. Winprop – Modelling of the phase behavior and properties of reservoir fluid. The application is very to use and can accurately characterize the reservoir fluid system by matching the laboratory PVT experiment, miscibility studies, prediction of asphaltene deposition and simulation of surface separator equipment.

iii. GEM (Generalized Equation of State Model Compositional Reservoir Simulator) – simulates complex reservoir model with varying fluid combination. GEM can be used to model CO2 injection and asphaltene modelling.

iv. STARS (Advance Process, and Thermal Reservoir Simulator) – three-phase multi-component thermal and steam additive simulator. It can used to model surfactant flooding, dual porosity, salinity flooding and others.

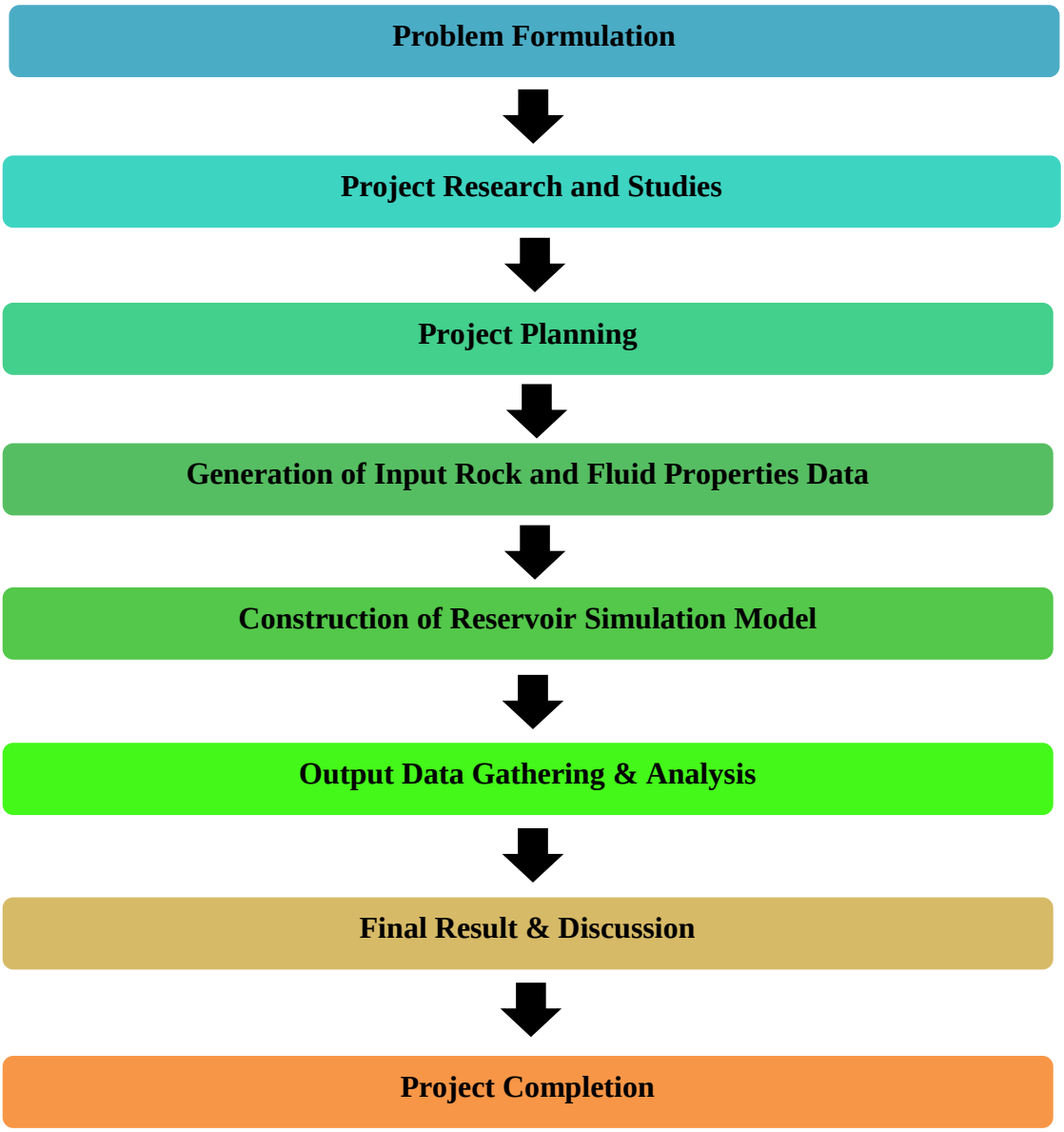
3.3 RESERVOIR AND FLUID MODELS

Two reservoir simulation models will be built which are:

- light crude oil reservoirs with asphaltene presence
- light crude oil reservoirs without asphaltene presence

The models then will go through several processes to reconstitute original reservoir condition such as natural depletion and water flooding. After it reaches third stage of production, optimization of WAG and FAWAG ($C0_2$) injection will be performed on all models to identify the effect of asphaltene precipitation by controlling slug size, injection rate, and surfactant concentration with means of recovery factor and permeability reduction

3.4 PROJECT ACTIVITIES



3.5 GANTT CHART AND KEY MILESTONES

Final Year Project I															
No	**Detail/ Week**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**
1	**Topic Selection**														
2	**Preliminary Research Work**														
3	**Extended Proposal**														
4	**Proposal Defense**														
4	**Project Work Continues**														
5	**Interim Draft Report Submission**														
6	**Submission of Interim Report**														

Key Milestone

Final Year Project II															
No	**Detail/ Week**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**
1	**Project Work Continues**														
2	**Submission of Progress Report**														
3	**Project Work Continues**														
4	**Pre-SEDEX**														
4	**Submission of Draft Final Report**														
5	**Submission of Dissertation (Softbound)**														
6	**Submission of Technical Paper**														
7	**Submission of Project Dissertation (Hardbound)**														

CHAPTER 4

RESULT

4.1 ASPHALTENE PRECIPITATION MODEL

The precipitation of asphaltene is modelled by using a multiphase flash calculation in which fluid phases are described with an equation of state and the fugacities of components in the solid phase are predicted using the solid model described below. The precipitated phase is represented as an ideal mixture of solid components. The fugacity of a precipitating component in the solid phase is:

$$\ln f_s = \ln f_s^{\,*} + \frac{v_s}{\mathrm{R}}\left[\frac{\mathrm{P}-P_{tp}}{\mathrm{T}} - \frac{\mathrm{P}^*-P_{tp}}{\mathrm{T}^*}\right] - \frac{\Delta H_{tp}}{R}\left[\frac{1}{T}-\frac{1}{T^*}\right] - \frac{\Delta C_p}{R}\left[\ln\left(\frac{T^*}{T}\right) - T_{tp}\left(\frac{1}{T}-\frac{1}{T^*}\right)\right]$$

where

f_s	=	fugacity at pressure P and temperature T
f_s^*	=	fugacity at pressure P^* and temperature T^*
v_s	=	solid phase molar volume of the component
ΔC_p	=	solid-liquid heat capacity difference
ΔH_{tp}	=	heat of fusion at triple point
P_{tp}	=	triple point pressure
T_{tp}	=	triple point temperature
R	=	universal gas constant

For isothermal predictions which used in this simulation, the equation can be simplified to give:

$$\ln f_s = \ln f_s^* + V_s (P - P^*)/RT$$

The process is reversible which any precipitated solid will go back to solution when the system is returned to a state outside the asphaltene precipitation envelope.

4.2 ASPHALTENE FLOCCULATION MODEL

Phenomenon of asphaltene flocculation of smaller asphaltene particles into larger aggregates can be modelled by allowing the thermodynamic asphaltene precipitate (solid s_1) to be transformed via a simple reversible chemical reaction into another solid, s_2. The reaction can be written as follows:

$$s_1 \leftrightarrow s_2$$

Rate of formation of s_2 is given by:

$$r = k_{12}C_1 - k_{21}C_2$$

where

k_{12}	=	forward rate of formation of solid s_2 from s_1 [day^{-1}]
k_{21}	=	reverse rate of formation of solid s_1 from s_2 [day^{-1}]
r	=	reaction rate [mol / (m^3 day)]
C_1	=	concentration of suspended solid s_1 in oil phase [mol / m^3]
C_2	=	concentration of suspended solid s_2 in oil phase [mol / m^3]

The reaction is reversible but may take a long time to complete as k_{21} approaching zero. On the other hand, if k_{21} is zero, the reaction is irreversible. The above chemical reaction allows the modelling of irreversible precipitation or a slow dissolution of the precipitated asphaltene.

4.3 ASPHALTENE DEPOSITIONAL MODEL

In the deposition model, only flocculated particle are considered to deposit. In reality, small asphaltene precipitate particle flow with oil phase while flocculated particle more likely to deposit on reservoir rock. Deposition rate equation as below:

$$\frac{V_{S_2^d}^{n+1} - V_{S_2^d}^{n}}{\Delta t} - \alpha C_{S_2^f}^{n+1} \phi^{n+1} + \beta V_{S_2^d}^{n+1} \left(V_o^n - V_{cr,o}\right) - \gamma u_o^n C_{S_2^f}^{n+1} = 0$$

where

$V_{S_2^d}$ = volume of deposited solid s_2 per grid block volume

$C_{S_2^f}$ = volumetric concentration of flowing solid s_2 per volume of oil

V_o = oil phase interstitial velocity

$V_{cr,o}$ = critical oil phase interstitial velocity

u_o = oil phase Darcy velocity

α = surface deposition rate coefficient

β = entrainment rate coefficient

γ = pore throat plugging rate coefficient

The surface deposition rate coefficient is a positive constant and dependent on type of rock. As interstitial velocity less than critical interstitial velocity, the entrainment rate coefficient is set as zero, and set to positive if vice-versa. If average pore throat diameter is larger than critical value, pore throat plugging coefficient is set to zero. If it is smaller, the coefficient is calculated as:

$$\gamma = \gamma_i (1 + \sigma V_{S_2^d})$$

γ_i = instantaneous pore throat plugging rate coefficient

σ = snowball-effect deposition constant

4.4 FLUID MODELLING USING WINPROP

The oil sample used in the study is taken from Burke et al (1990) literature. In the literature, there five oil samples which have asphaltene content and for this study oil sample with API 38.8 (light oil) will be used. The component of the oil are listed as below in table 1.

Table 1: Burke Oil 38.8 (light oil) properties

Component	Burke Oil 38.8
Nitrogen, N2	0.25
Carbon Dioxide, CO_2	2.03
Methane, C_1	32.44
Ethane, C_2	15.50
Propane, C_3	6.54
i-Butane, IC_4	0.81
n-Butane, NC_4	3.20
i-Pentane, IC_5	1.15
n-Pentane, NC_5	2.13
Hexanes, FC_6	2.46
Heptanes plus, C_{7+}	33.49
Total	**100.00**
C_{7+} molecular weight	223
C_{7+} specific gravity	0.8423
API gravity, stock tank oil	**38.8**
Reservoir temperature, °F	234
Saturation pressure, psia	2492

To model the fluid, author has used Peng-Robinson (1978) method in calculating Equation of State. There are several steps in defining the oil through Winprop which are selection of fluid component as data provided and further component characterization of C7+ through Plus Fraction Splitting, regression, and prediction of precipitated behavior.

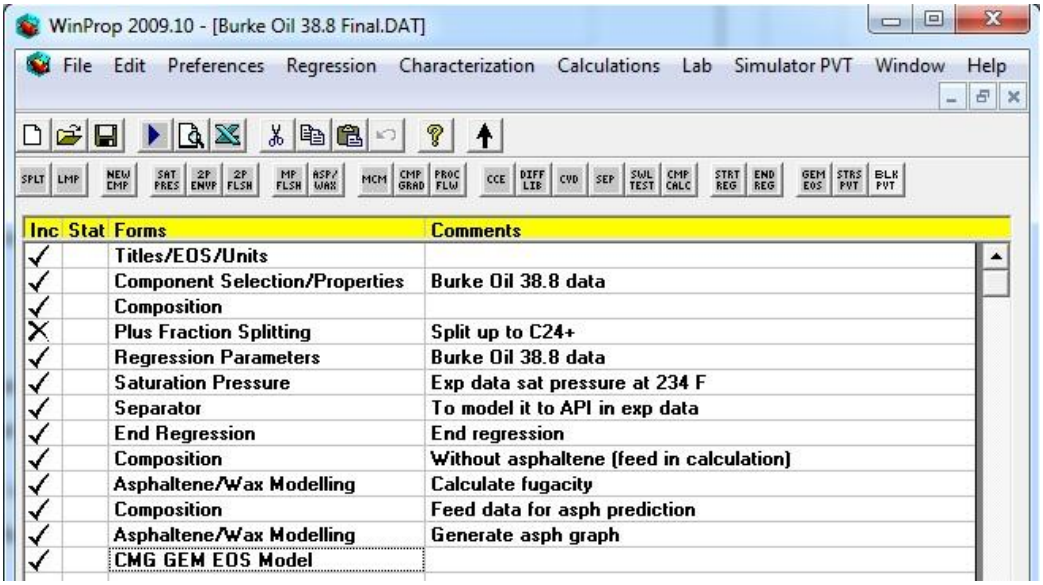


Figure 2: Winprop data

First, every component were included in the composition except C_{7+}. In order to better define the asphaltene deposition, the C_{7+} component is split into several components. Molecular weight, specific gravity and mole fraction of component C_{7+} are keyed into Winprop to generate the fraction splitting as shown in Figure 3. 2-stage exponential distribution with Log (K) lumping method, and Lee-Kesler correlation are used.

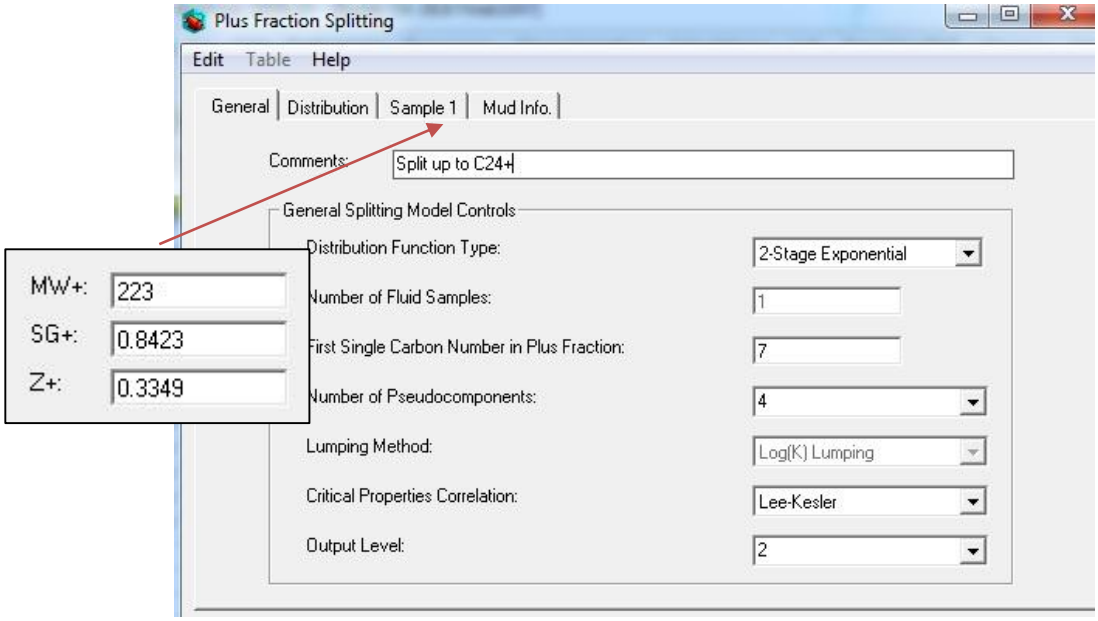


Figure 3: Plus Fraction Splitting

After splitting, the oil data is regressed to match the saturation pressure and hydrocarbon interaction coefficient. In order simulate the asphaltene precipitation, it is crucial to first characterize the asphaltene component both in solution and in solid phase. Author did splitting again the heaviest components split into two components, a precipitating fraction and non-precipitating component. The non-precipitating component is the C_{24A+} fraction and the precipitating component is C_{24B+} fraction. Both components have identical acentric factors and critical properties, however different interaction parameters which C_{24B+} only has interaction from C_1 until C_5 and it has higher interaction compared to C_{24A+} component. Mole fraction of precipitating component, can be obtained by using formula below:

$$X_{asphaltene}\, MW_{\ asphaltene} = W_{asphaltene}\, MW_{oil}$$

The asphaltene content of stock tank oil is given in the data as 1.7%. From the result of regression, the molecular weight of the oil is 223. Molecular weight of heaviest component is 461.442. The modeled components after calculation of splitting as shown in Table 2:

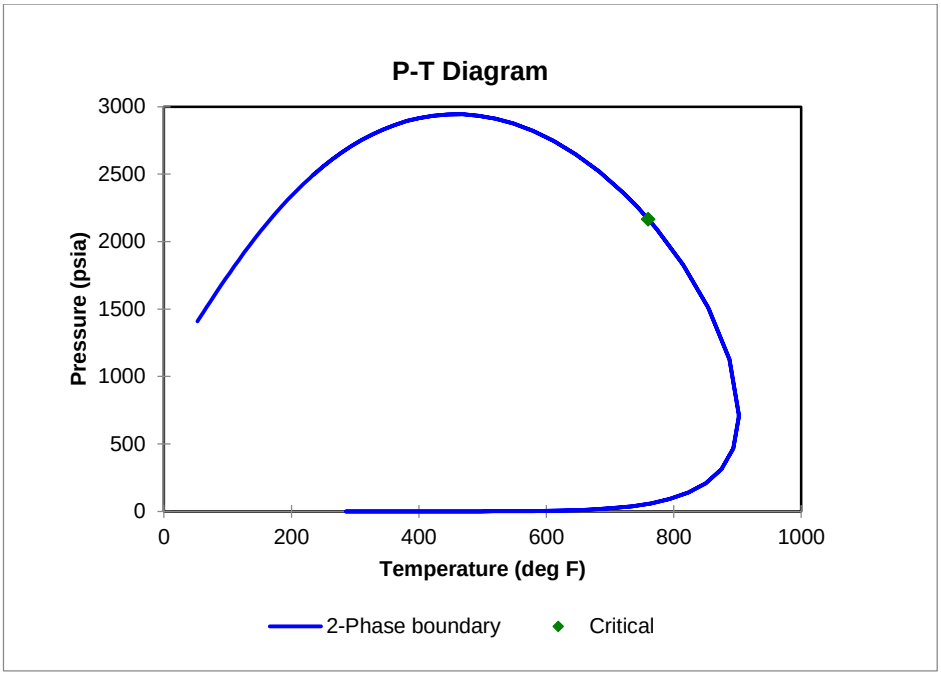


Figure 4: Two phase Envelope of Burke Oil 38.8

The critical temperature for the fluid is 760 F and critical pressure is at 2166.78 psia. While cricondenbar is at 2940 psia and cricondentherm is at 902 F. To actuate an under saturated reservoir, the reservoir pressure must be set above saturation pressure. The primary recovery drive mechanism of the reservoir will be from solution gas drive.

Table 2: Modelled Fluid Composition For Burke Oil 38.8

Burke Oil 38.8		
Component	Molecular Weight	Mole Fraction
N2	28.013	0.0025
CO2	44.010	0.0203
C1	16.043	0.3244
C2	30.070	0.155
C3	44.097	0.0654
IC4	58.124	0.0081
NC4	58.124	0.032
IC5	72.151	0.0115
NC5	75.151	0.0213
FC6	86.000	0.0246
C7 – C12	127.35883	0.15675355
C13 – C17	205.83943	0.072870575
C18 – C23	281.64483	0.049275506
C24A+	461.442	0.052493101
C24B+	461.442	0.0035072664

After characterizing the asphaltene component, the model fluid is again regressed to fit API gravity in experimental data. From the calculation of fugacity, molar volume of asphaltene precipitation is set at 0.66, while interaction coefficient of C_{24B+} with C1 – C5 is set at 0.37.

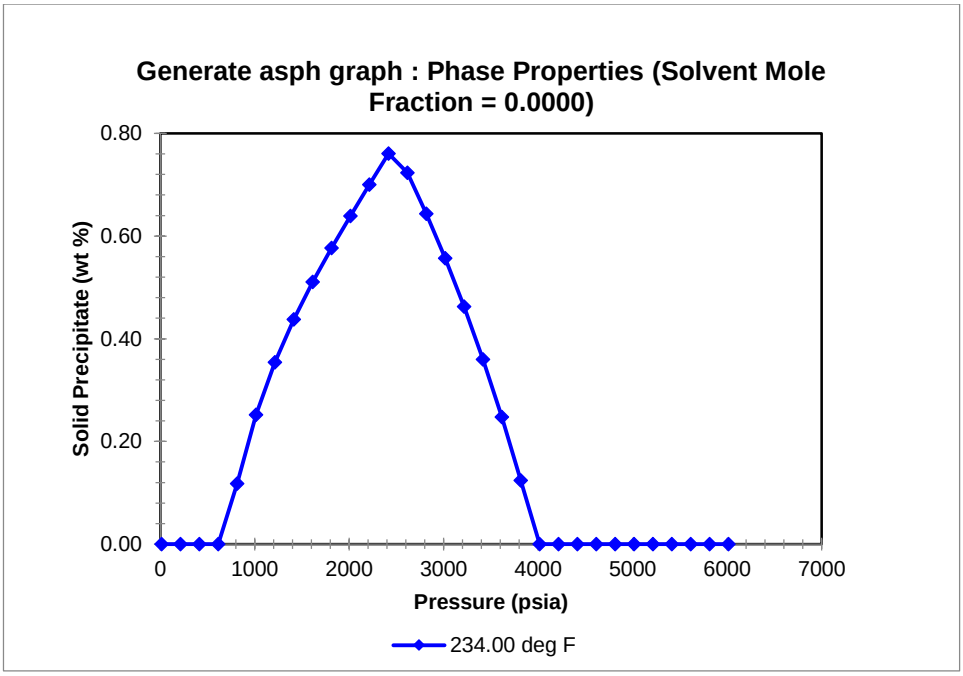


Figure 5: Modeled Asphaltene Precipitation as a function of Pressure

As shown in Figure 5, Asphaltene Onset Pressure (AOP) is surrounding the saturation pressure which it is bounded within asphaltene precipitation region range between the upper AOP and lower AOP (Teoh, 2012). Hence, making the result accurate as maximum precipitation of asphaltene occurred around 2415 psia and Burke Oil 38.8 saturation pressure is at 2492 psia. Lower AOP is at 615 psia while upper AOP is at 4000 psia. As pressure declines, amount of precipitated asphaltene increases, where it reaches maximum at or very near saturation pressure due to compositional change. However as pressure decreases after saturation pressure, precipitated asphaltene decreases due to lighter components leaving behind heavier components in the oil which will solute the asphaltene back into the crude oil.

4.5 RESERVOIR MODELLING USING BUILDER

In this part, author will discuss on simulation of reservoir model by using Builder which supports all three CMG simulators, IMEX, GEM and STARS. Builder covers all areas of data input including creating grid and grid properties, rock-fluid model, locating wells, setting initial conditions and creating fluid models. Builder can split grid block in each of I, J and K directions and each reservoir model can be converted from one simulator into another. All simulations is ran on a heterogeneous formation. Below are 2D view of the reservoir:

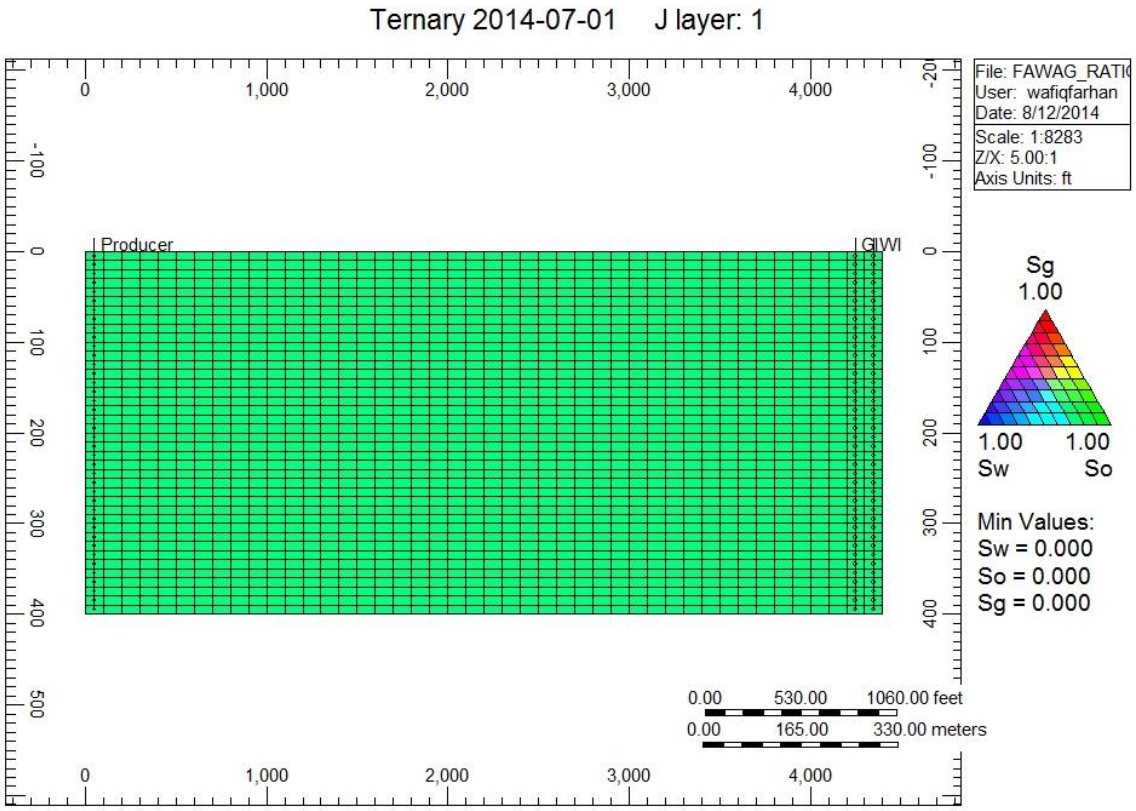


Figure 6: Grid block (40x1x44)

The two fluid injector are placed at left end of the reservoir and producer is placed at the right end of the reservoir. The reservoir is built with configuration 40 x 100ft, 1 x 10 ft, and 44 x 1 ft with total of 1760 grid blocks. The reservoir is input as heterogeneous. The permeability variations are tabulated in appendix.

All models will using same specification of reservoir data, and well data as shown in Table 3 and 4 below:

Table 3: Main Reservoir Properties

Reservoir data	
Reservoir Pressure	3500 psia
Reservoir Temperature	234 °F
Porosity	0.20
Oil Saturation	0.78
Connate Water Saturation	0.22
Grid Block Dimension (X x Y x Z)	44 x 1 x 40 (X = 4400 ft, Y = 10ft, Z =40ft)
Initial Condition	Undersaturated reservoir
Well data	
Injector constraint	Maximum bottomhole pressure = 3500 psia
Injector location	1,1,1 until 1,1,40
Producer constraint	Minimum bottomhole pressure = 2500 psia
Injector location	44,1,1 until 44,1,40
Injector fluids	Surfactant, water, CO_2
EOR process	Water Alternating Gas Foam-assisted Water Alternating Gas
Perforation	40 ft (all layers)

Table 4: Reservoir Data

Total bulk volume, res ft3	1.76×10^7
Total pore volume, res ft3	3.52×10^6
Total hydrocarbon pore volume, res ft3	2.7456×10^6
Original oil in place, std bbl	489×10^3

After importing fluid model data from Winprop into Builder, authors has to input rock-fluid interaction which requires several essential element of rock properties such as connate water, critical water saturation, and residual oil saturation. The aforementioned inputs are important in correlating relative permeability of fluid which used Corey's correlation as generalized as below:

Krw = Krwiro * ((Sw - Swcrit)/(1.0 - Swcrit - Soirw))**Nw

Krow= Krocw * ((So - Sorw)/(1.0 - Swcon - Sorw))**Now

Krog=Krogcg*((Sl - Sorg - Swcon)/(1.0 - Sgcon - Sorg - Swcon))**Nog

Krg =Krgcl *((Sg - Sgcrit)/(1.0 - Sgcrit - Soirg - Swcon))**Ng

Below are the saturation diagram in the reservoir and relative permeability curve plotted in the simulation:

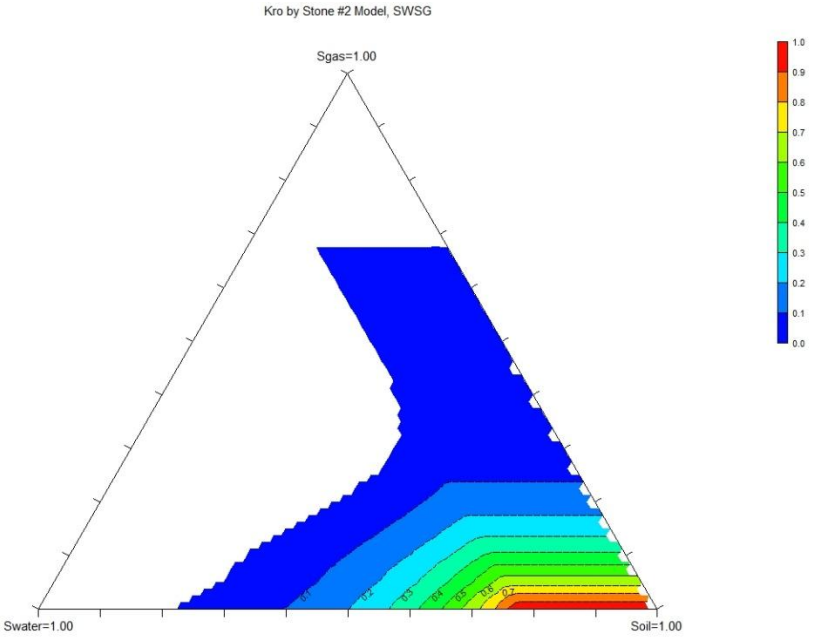


Figure 7: Saturation Diagram

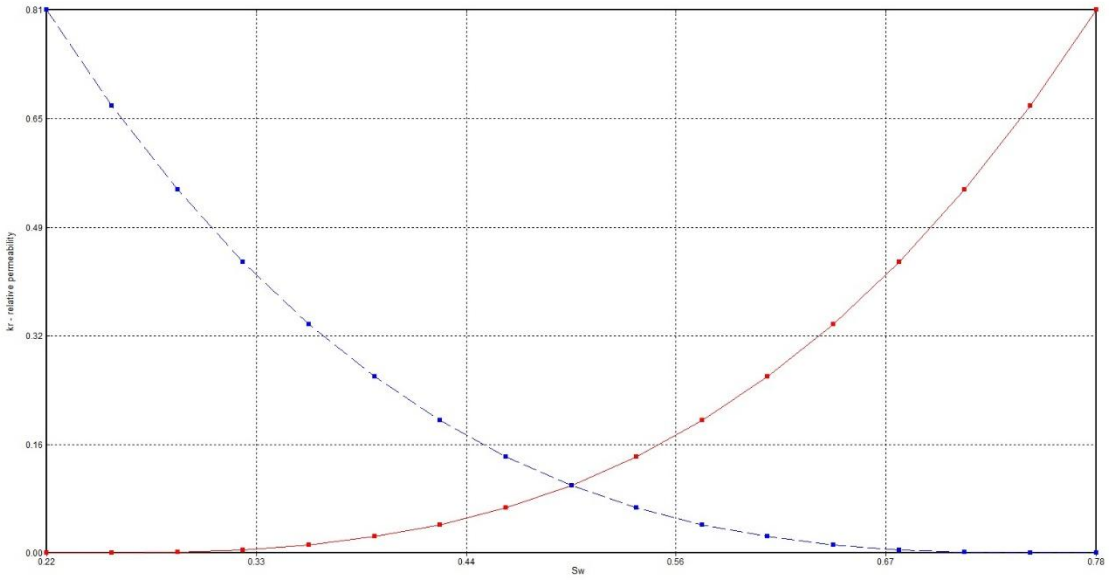


Figure 8: Relative Permeability Curve

The mixed wettability nature of the reservoir as indicated in Figure 7 with intersection point of higher than 0.5 and the end points for both relative permeability of water and oil is same. This permeability will change depend upon the compositional change of fluid injected.

4.3 PREPARING RESERVOIR MODEL

Simulation runs are performed for three different scenarios for WAG-CO_2 and FAWAG-CO_2 injection in with and without asphaltene presence comprising pore volume (PV) ratio of 1:1, 1:2 and 2:1. Another simulation is run on 1:1 ratio with different concentration of surfactant to determine optimum concentration surfactant.

The simulated reservoir is first gone through natural depletion and waterflooding for 4 years with total of 0.4 PV before EOR process is applied. The waterflooding is stopped at 4th year of production due to economical limit set in the simulator when the percentage of water cut is above 80 percent of total fluid production. Duration of simulation from initial reservoir condition until end of waterflooding is from 1st July 2014 until 1st August 2018.

To study the effect of PV ratio, 12 cycles is used with duration of 6 month per cycles. A constant amount of surfactant concentration (0.0005%) is used in the study to avoid effect of surfactant concentration in the study. Injection as PV ratio is tabulated in table 5 below:

Table 5: PV Ratio with Injection Rate

PV Ratio (Water to CO_2 ratio)	Injection rate
1:1	696 barrels/day : 696 barrels/day
2:1	1393 barrels/day : 696 barrels/day
1:2	696 barrels/day : 2089 barrels/day

In finding optimum concentration of surfactant, FAWAG ratio of 1:1 is used. Total of nine simulation runs are performed to identify the effect of surfactant concentration towards recovery factor and cost estimation. The range of surfactant concentration is from 0.00002% - 0.008%.

4.4 COMPARISON BETWEEN FAWAG WITH AND WITHOUT ASPHALTENE

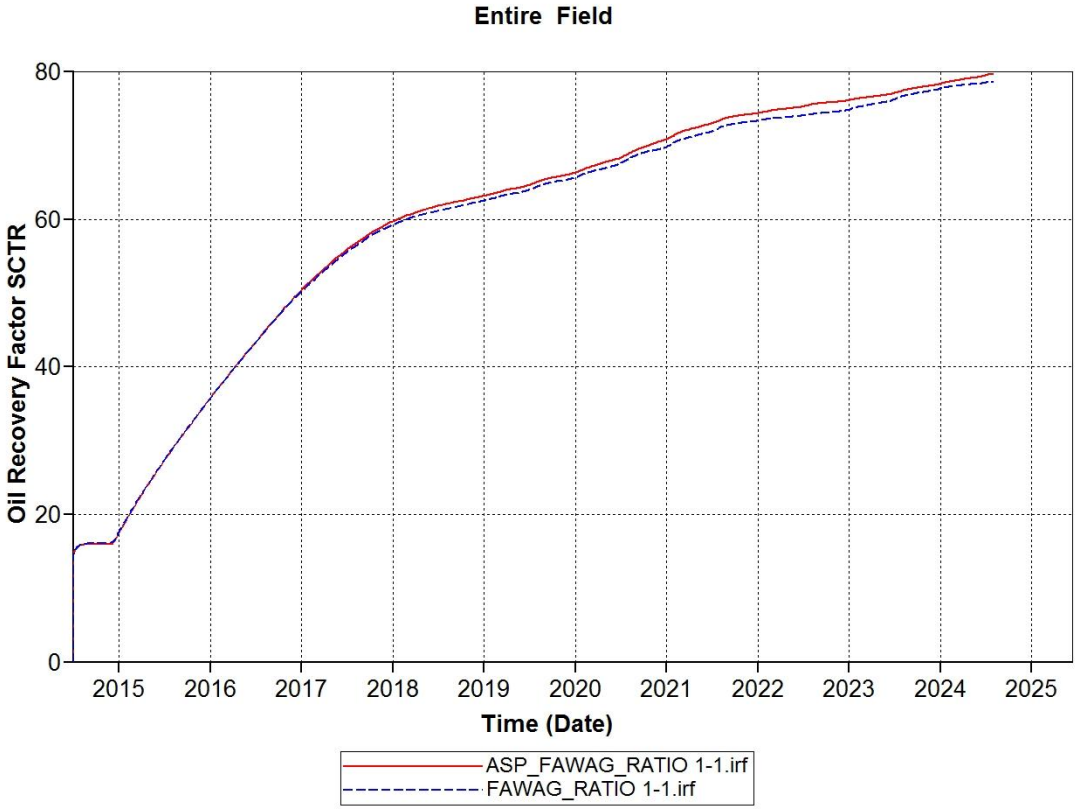


Figure 9: FAWAG model with and without Asphaltene

The results from Figure 9 showed that FAWAG with asphaltene content recovery more oil than FAWAG without asphaltene content. In the FAWAG with asphaltene model, as gas is injected into the reservoir, it tends to travel upward rather than lateral due to permeability variation and gravity segregation. As the gas flows toward oil, asphaltene precipitation is induced. According to Ali (2009), mixing of gas with asphaltene presence-oil will enhance the deposition of asphaltene. The precipitation of asphaltene is significantly induced when gas injection is started since it will swell the oil and decrease the solubility of asphaltene. Hence, as the gas moving upward asphaltene is induced, more asphaltene is deposited at the upper most layer and the high permeability layers, which resulted in gas pushing to the lower permeability layers which contained more oil than high permeability layers. Thus, implementation of FAWAG in asphaltene-presence reservoir will have a great significant increase in oil recovery.

4.5 COMPARISON BETWEEN WAG WITH AND WITHOUT ASPHALTENE

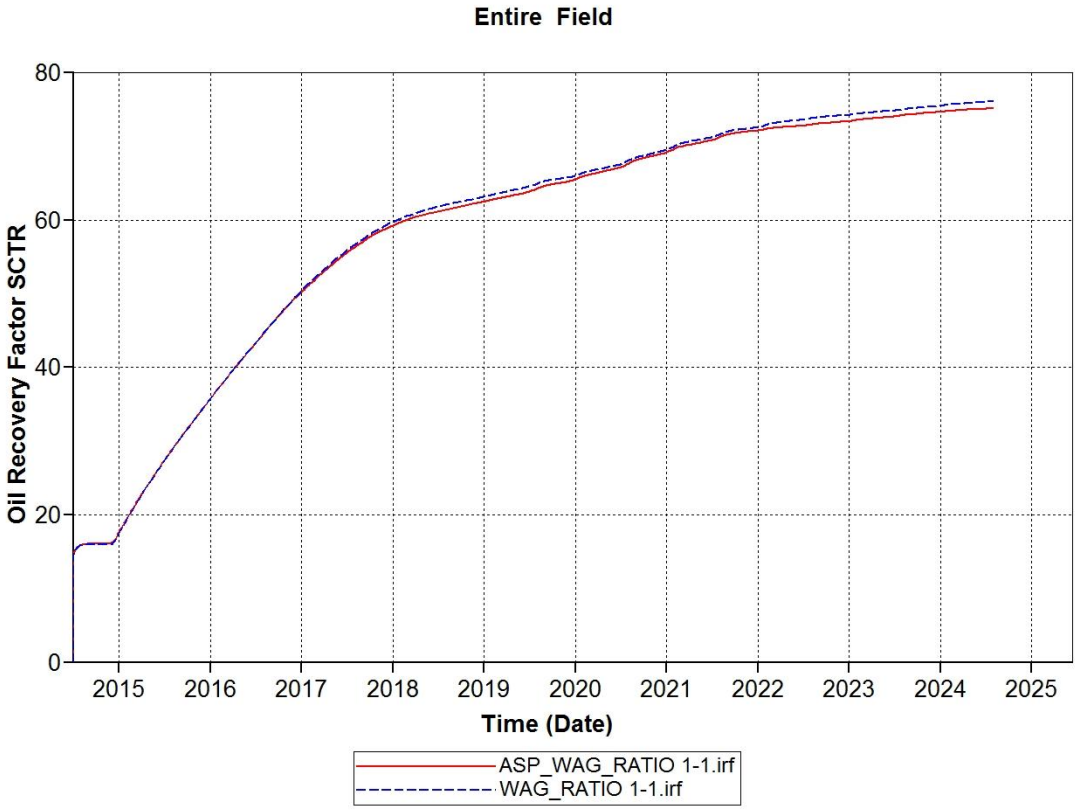


Figure 10: WAG model with and without asphaltene

Based on Figure 10, WAG model without asphaltene has better recovery than WAG with asphaltene. This phenomena is due to deposition of asphaltene reduced the permeability of reservoir which results in reduction in overall recovery. According to Ghedan (2009), deposition of asphaltene can induce declination of both permeability and porosity in the reservoir. The deposition of asphaltene cannot be seen from the starting of simulation. However, it can be clearly seen after water breakthrough during waterflooding process. During this process, the reservoir pressure rapidly declined and the fraction of C1-C5 which solute the asphaltene starts to produce as gas. After WAG is applied, reduction in average recovery in asphaltene model which concurrent with application of CO_2. The injected gas will depreciate the solubility of asphaltene, induced the asphaltene deposition. Although the difference in recovery is less significant, however WAG without asphaltene is having higher production rate compared to WAG with asphaltene model. Hence, it is proven that asphaltene

deposition can caused clogged pore throat which directly contributes to reduction of reservoir permeability.

4.6 COMPARISON BETWEEN FAWAG AND WAG WITHOUT ASPHALTENE

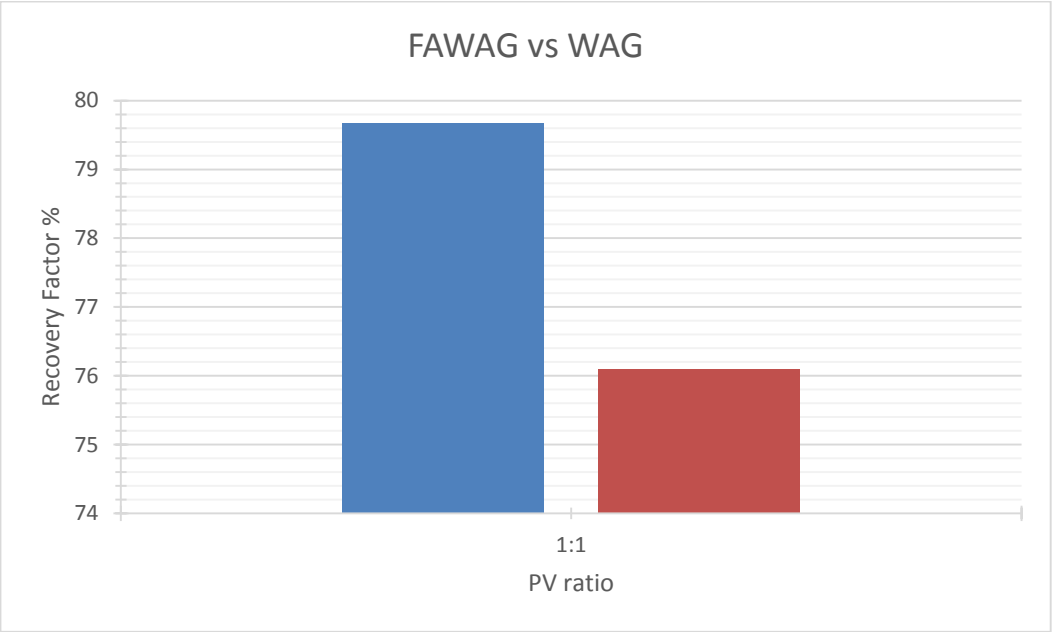


Figure 11: FAWAG versus WAG without asphaltene

A clear difference in recovery factory percentage between FAWAG and WAG injection in same PV ratio 1:1. A difference of 3.4% of total recovery from FAWAG and WAG. The WAG process only use water to control mobility of gas which eventually will caused early gas breakthrough. The gas will bypass low permeability layers and go through less resistance passage. While in FAWAG, foam is formed and block the gas from entering high permeability layers while pushing the oil through the foam by mechanism of gas and the additional gas will push the low permeability which at the end results in higher recovery compared to WAG injection. Although there is no significant difference in number of recovery, it is due to 0.00005 concentration of surfactant is used which still under optimization. The optimum concentration of surfactant in ratio 1:1 will be studied in the next result.

4.7 COMPARISON BETWEEN FAWAG AND WAG WITH ASPHALTENE

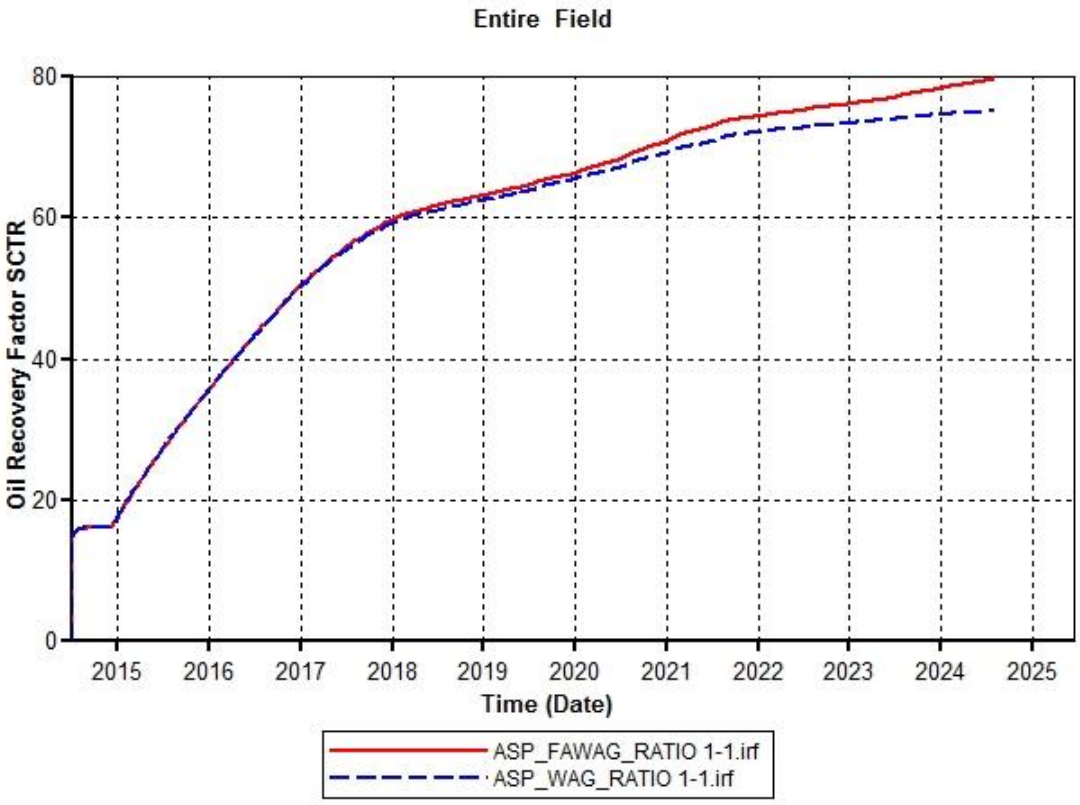


Figure 12: FAWAG versus WAG with asphaltene

In Figure 12, FAWAG injection showed significant better recovery than WAG in the presence of asphaltene. This showing that FAWAG is more likely to be applied in asphaltene-presence reservoir instead of WAG. Higher recovery by FAWAG is due to better gas mobility control by formation of foam at high permeability layers. As the foam is forming barrier that blocking the gas from entering high permeability zone which the gas has to travel along low permeability layers, ultimately increased the recovery. This theory supported by Saleem (2011) which found that FAWAG has better mobility control over gas. Another explanation of the result was the introduction of surfactant improved the interfacial tension of water and oil. Precipitation of asphaltene can alter the wettability of rock surface. Hence, the reduction of interfacial tension need to be further reduced in order to obtained higher recovery.

4.8 COMPARISON BETWEEN WAG PORE VOLUME RATIO WITH ASPHALTENE

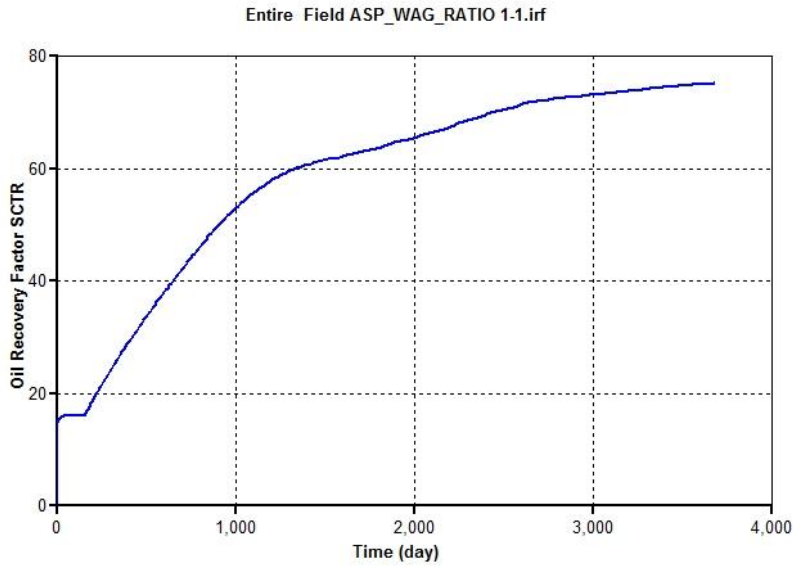


Figure 13: WAG ratio 1:1 with asphaltene

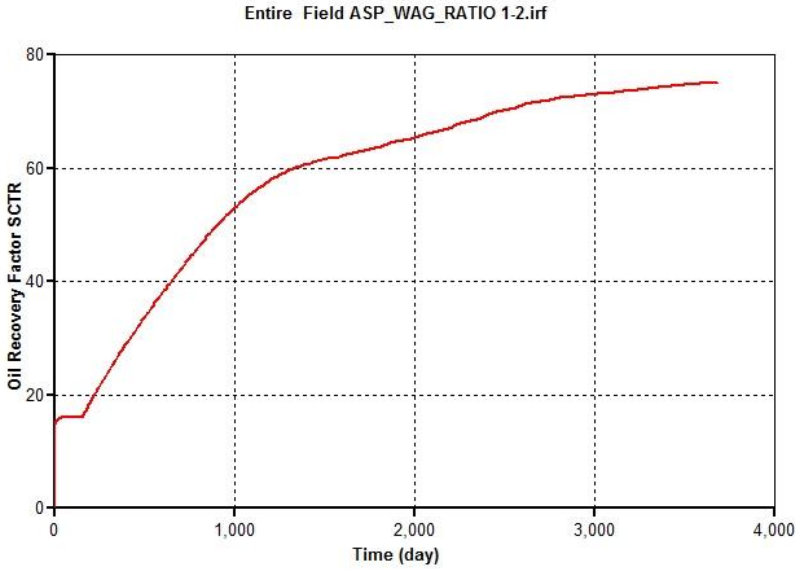


Figure 14: WAG ratio 1:2 with asphaltene

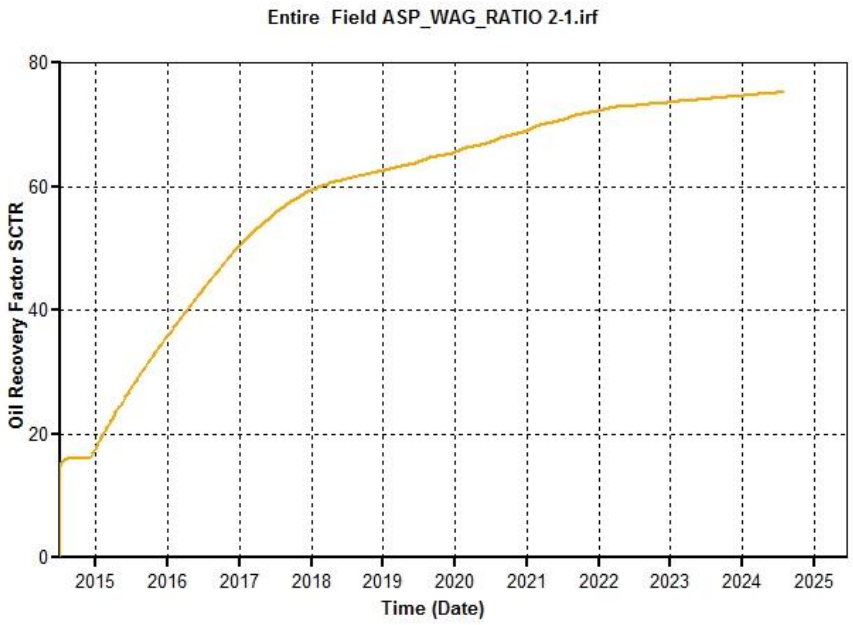


Figure 15: WAG ratio 2:1 with asphaltene

According to the Figure 15, the optimum ratio of WAG injection with presence of asphaltene is 2:1. The ratio 2:1 showed the highest recovery compared to 1:1 and 1:2. As WAG process is injected into the reservoir, the volume of water need to be sufficient enough to have good displacement efficiency. Insufficient injection rate (in term of PV) will result in poor oil displacement. Ratio 1:2 showed lowest recovery compared to others. Injection of gas can change the compositional fluid inside the oil, which will affect the solubility of asphaltene. Higher amount of gas injected into the reservoir will induce more asphaltene precipitation and more void space will be deposited by asphaltene. The deposited asphaltene will then plug the pore throat and increase the resistance of oil to flow. Hence, introducing more gas injection into the well will cause lower recovery.

4.9 COMPARISON BETWEEN WAG PORE VOLUME RATIO WITHOUT ASPHALTENE

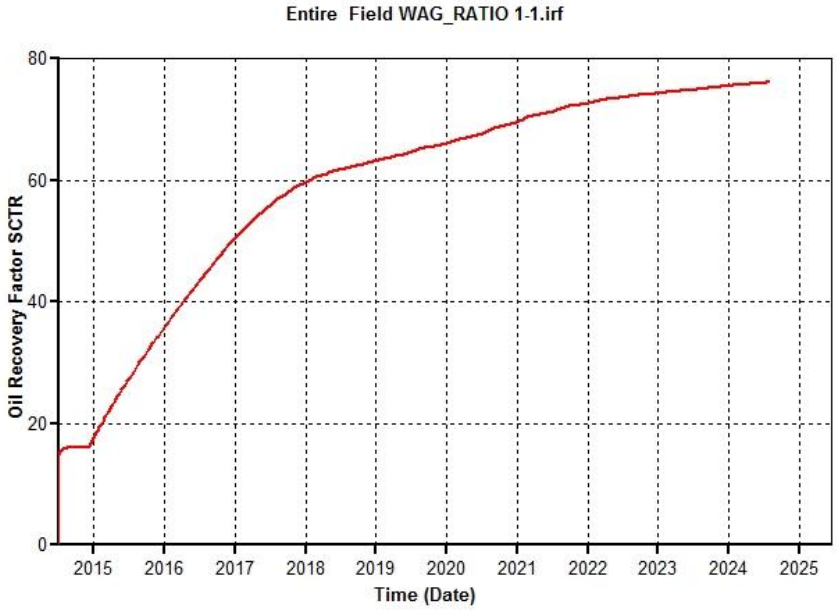


Figure 16: WAG ratio 1:1 without asphaltene

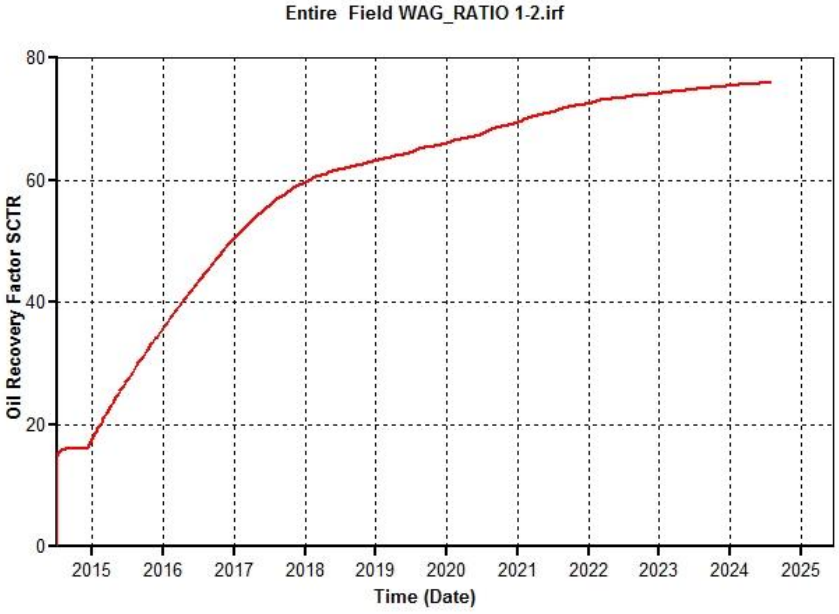


Figure 17: WAG ratio 1:2 without asphaltene

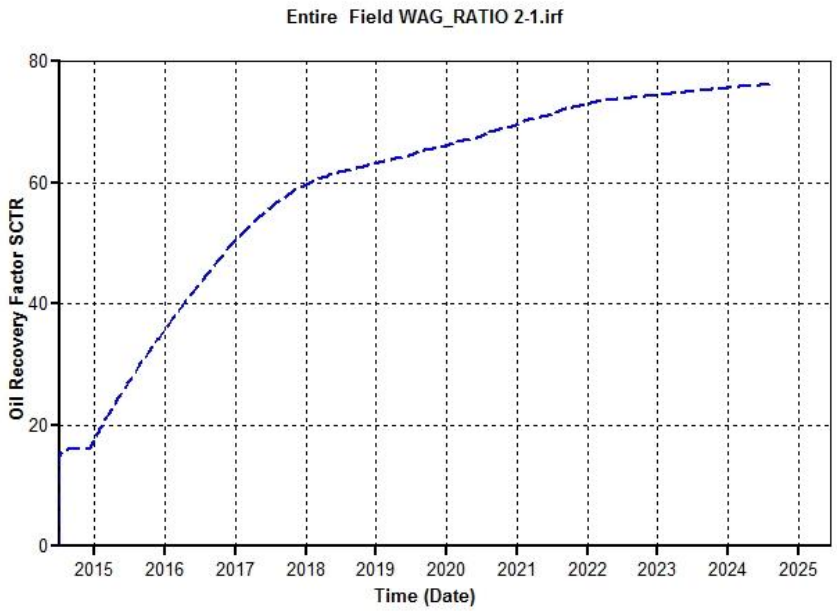


Figure 18: WAG ratio 2:1 without asphaltene

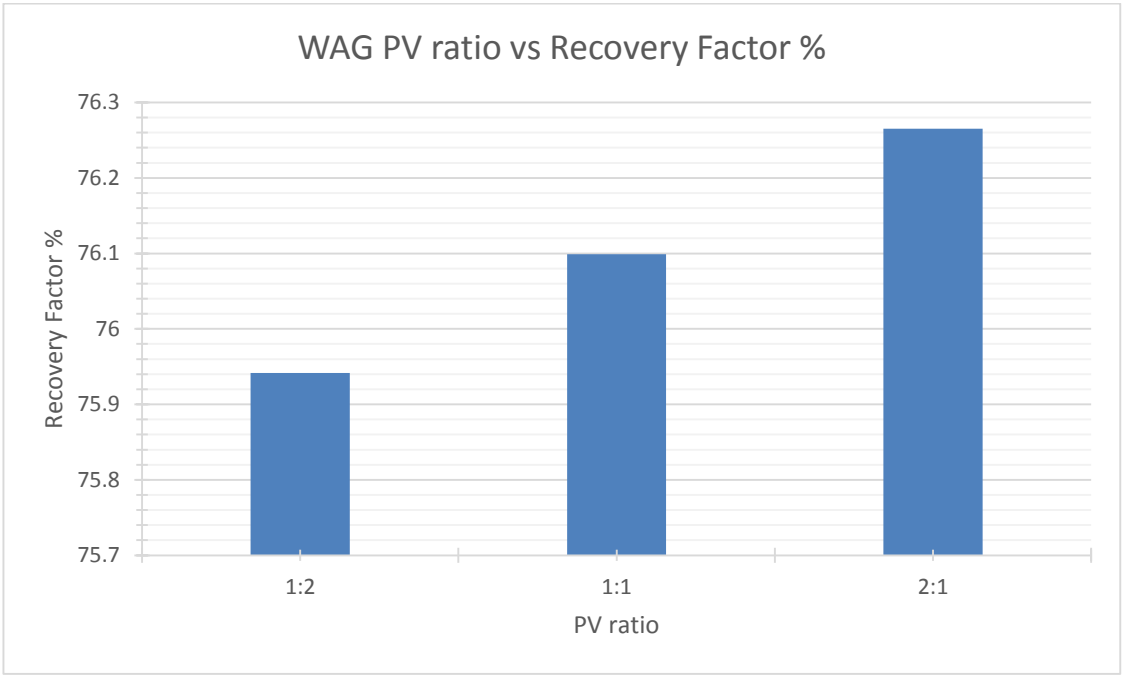


Figure 19: WAG PV ratio (without asphaltene) versus Recovery Factor

Based on Figure 19, WAG ratio of 2:1 shown highest recovery followed by 1:1 then 1:2. This indicated that WAG injection is more preferable with more water injection. The water will improve mobility control over the injected gas by increasing relative permeability of water. Ratio of 1:2 shown lowest in recovery factor due to

high amount of CO_2 will cause early breakthrough thus decreasing the recovery factor. In the synthetic reservoir model, variation of high and low permeabilities by layers are introduced. The tendency of gas to bypass through high permeability layers are highly to occur. Once gas breakthrough is occurred, the remaining injected gas become less efficient in pushing the oil due to it flows through less resistance path that created by breakthrough. The gas will bypass the low permeability layers, hence low displacement in low permeability layers. Apart from high permeability layers, gravity segregation due to different density will affect the breakthrough. The gas tends to flow upwards rather than displace oil through lateral. The result of ratio 1:2 can be compared with 1:1 which difference in 0.1574%. Higher amount of injected water will control the gas mobility and avoid early breakthrough, hence improving the recovery factor.

4.10 COMPARISON BETWEEN FAWAG PORE VOLUME RATIO WITH ASPHALTENE

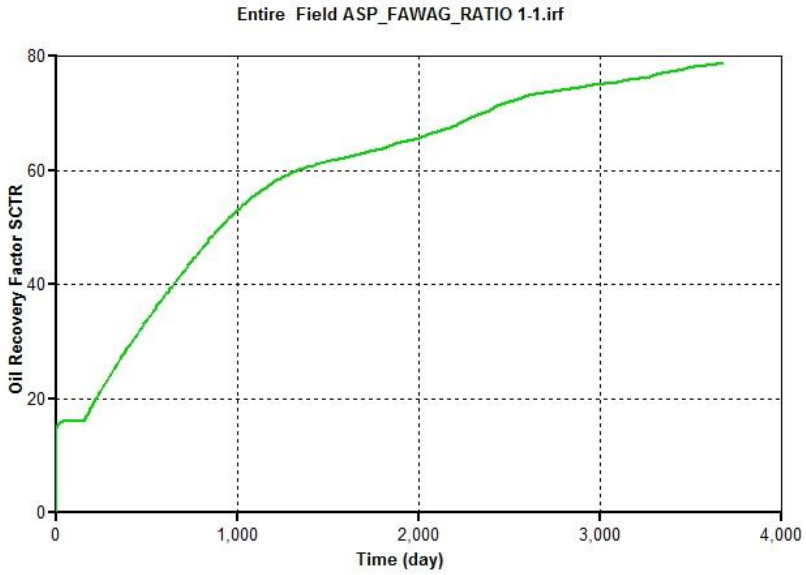


Figure 20: FAWAG ratio 1:1 with asphaltene

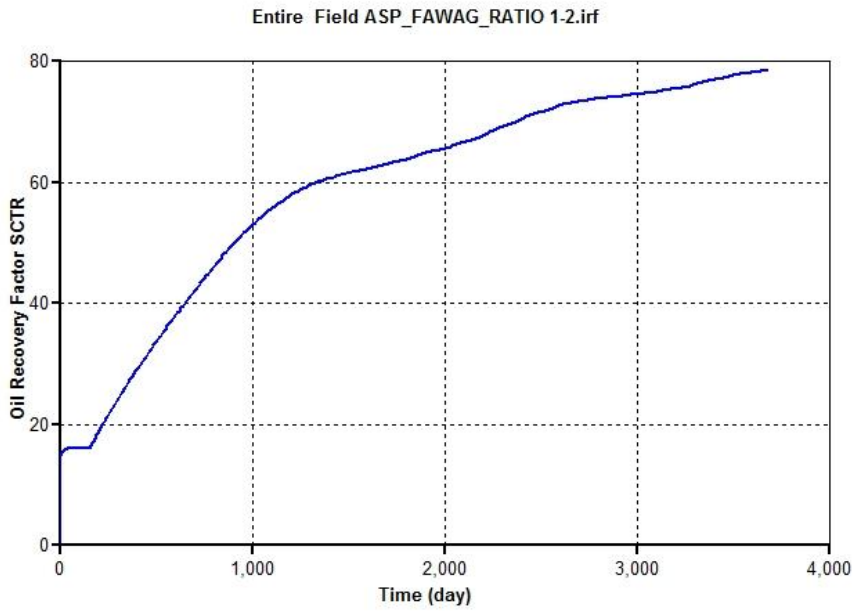


Figure 21: FAWAG ratio 1:2 with asphaltene

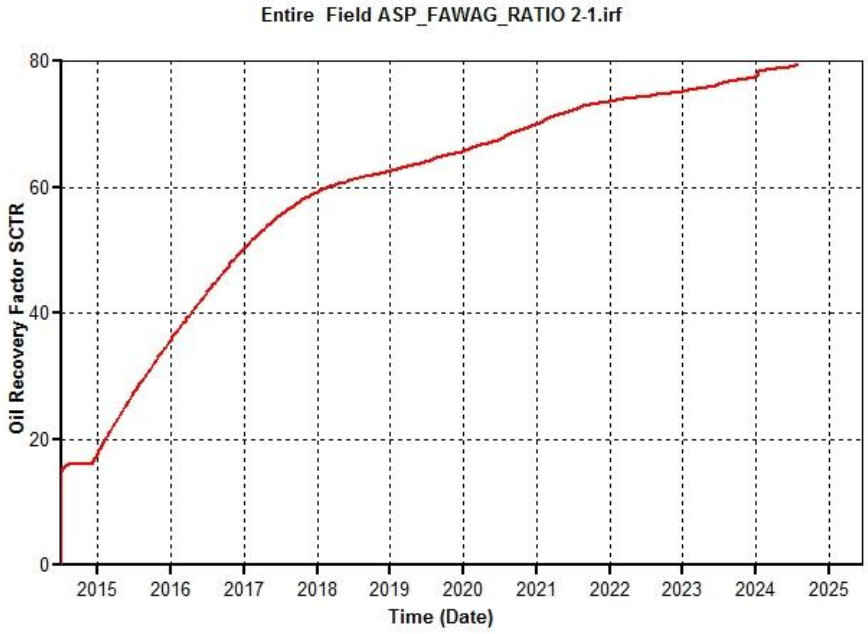


Figure 22: FAWAG ratio 2:1 with asphaltene

Based on Figure 20-22, ratio 2:1 yielded highest recovery than other two, followed by ratio 1:1 then 1:2. During FAWAG-CO_2 injection, surfactant is

introduced to improve the mobility control of gas by means of forming foams that blocking gas from passing through high permeability layers or upper layers by means of gravity segregation. In the reservoir, the injected CO_2 may react with reservoir fluid, causing the oil to swell which will lead towards asphaltene precipitation and deposition. Ratio 1:2 showed lowest recovery is due to injected gas may induce the asphaltene precipitation and cause reduction in permeability, hence results in lower recovery. There several reasons why ratio 2:1 has better recovery factor. First, high permeability layers is blocked by foam and injected gas channeled to unsweep layers which lead to better cumulative of produced oil. Second, pressure variation along high permeability layers caused asphaltene deposition. The deposition of asphaltene plugged pore throat and reduce the displacement efficiency at high permeability layers which will force injected fluid to travel along low permeability layers. Third, amount of injected is sufficient have good displacement efficiency. The ratio 2:1 displacement efficiency can be compared with ratio 1:1 where low amount of water is injected.

4.11 COMPARISON BETWEEN FAWAG PORE VOLUME RATIO WITHOUT ASPHALTENE

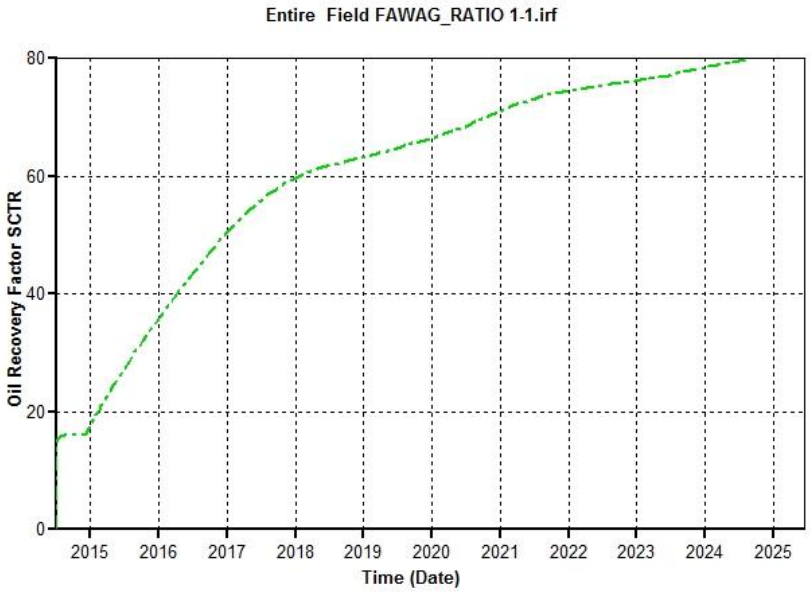


Figure 23: FAWAG ratio 1:1 without asphaltene

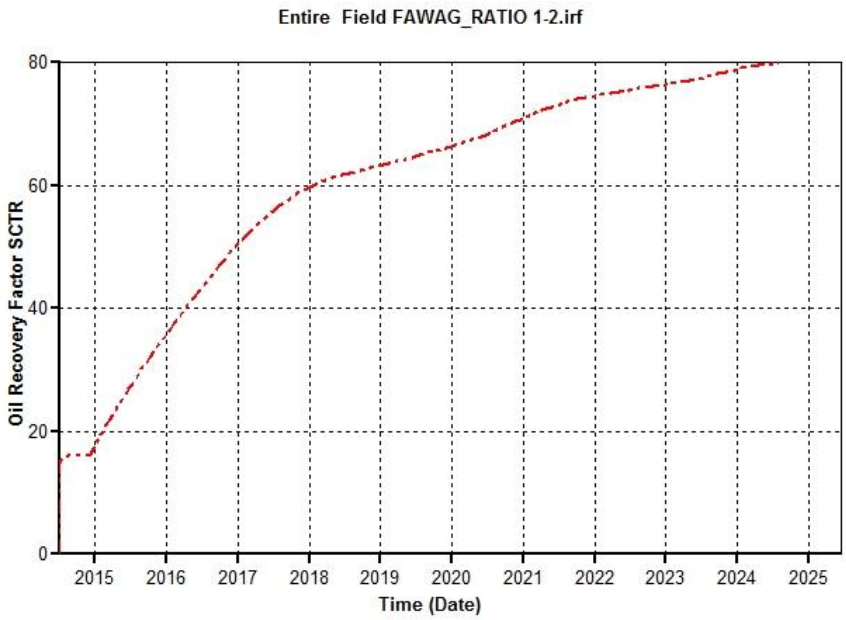


Figure 24: FAWAG ratio 1:2 without asphaltene

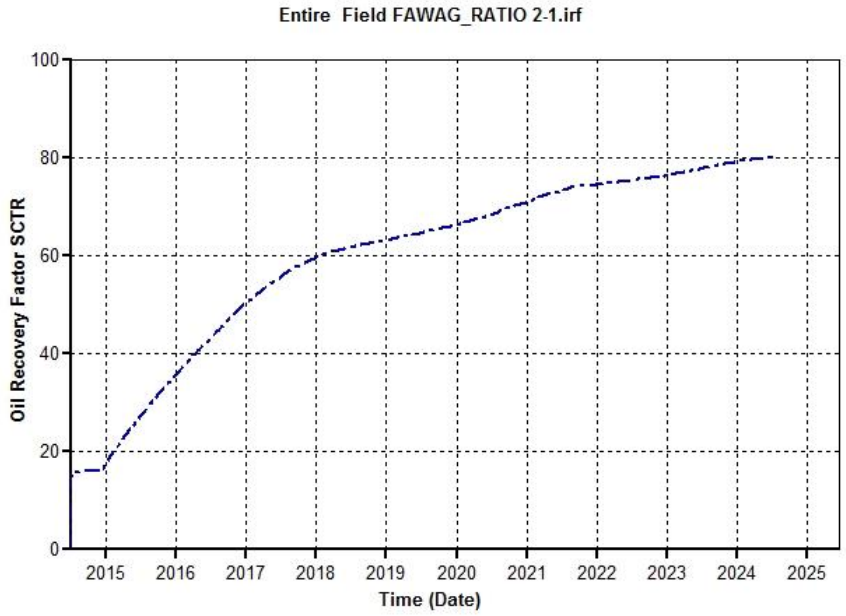


Figure 25: FAWAG ratio 2:1 without asphaltene

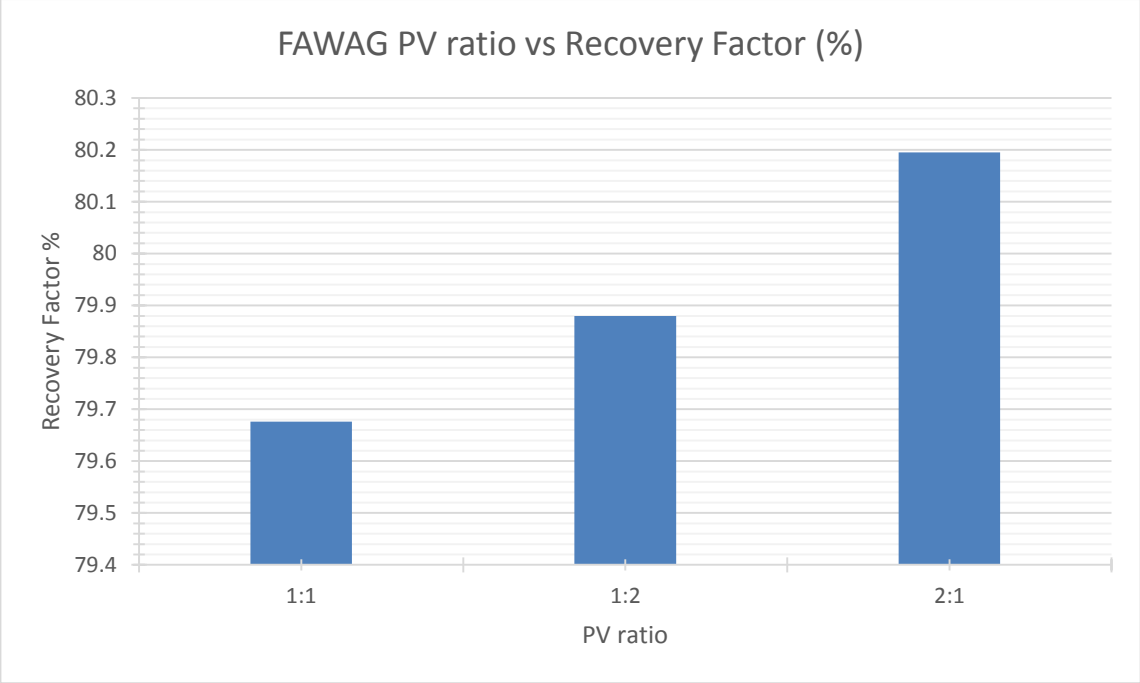


Figure 26: FAWAG PV ratio (without asphaltene) versus Recovery Factor

Based on Figure 26, the optimum FAWAG ratio is 2:1 followed by 1:2 and 1:1. Highest recovery by ratio 2:1 is due to FAWAG requires more water to generate foam. Higher water-surfactant injection into the reservoir will optimize the amount of gas injected and envelope the gas into bubble. The foam then will block additional gas from entering high permeability zone or upper layer (due to gravity segregation) and the gas will push oil along the low permeability zone. High water saturation in the reservoir is required to maintain the foam from collapsing. Compared to ratio 1:2 which utilized more gas injection, the injected surfactant cannot cover additional gas intake to form bubble. However, the gas nevertheless will push the oil along other high permeability zone and cause gas breakthrough which makes the total recovery factor less than ratio 2:1. Ratio 1:1 shown the lowest recovery factor than other due to the ratio is underutilized, the amount of injected surfactant and CO_2 is not proportional to each other. With ratio 1:1, the surfactant only create foam and no additional gas is pushing oil toward production well.

4.12 SURFACTANT CONCENTRATION VERSUS RECOVERY FACTORY

To produce optimum result, same ratio of 1:1 is used. Concentration of surfactant is ranged from 0.00002 until 0.008. The graph of surfactant concentration versus recovery factor is described as below:

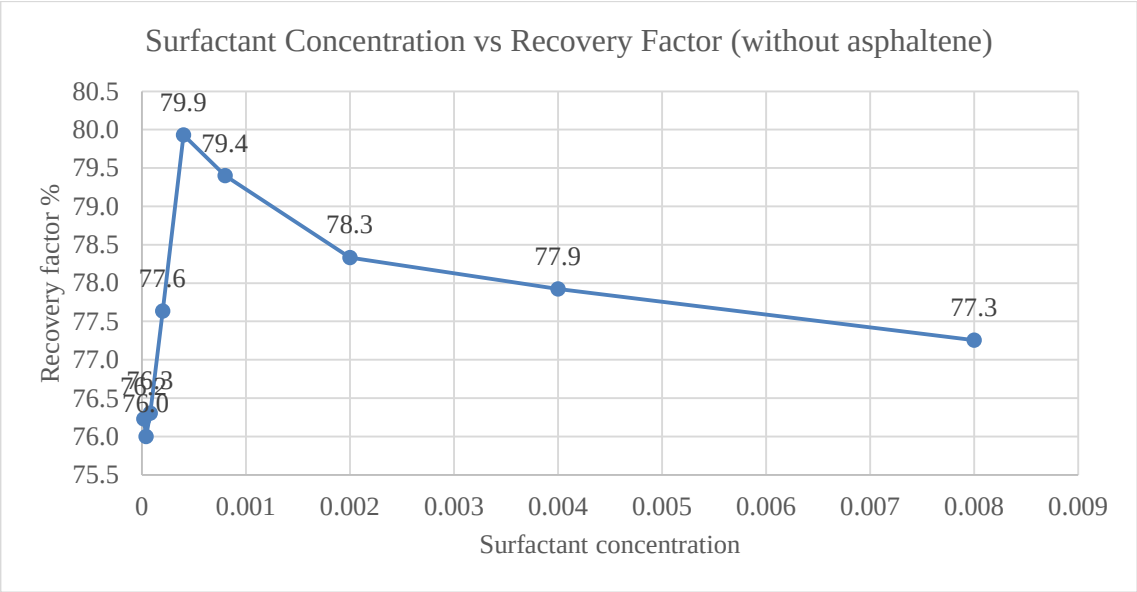


Figure 27: Surfactant Concentration versus Recovery Factor (without asphaltene)

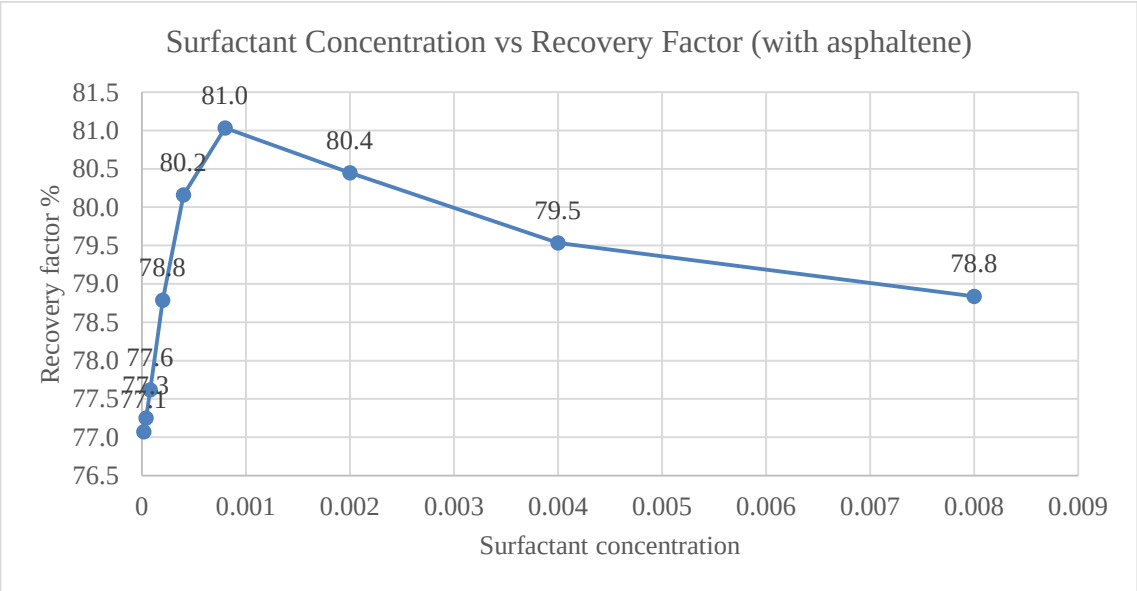


Figure 28: Surfactant concentration versus Recovery Factor (with asphaltene)

As shown in Figure 27, the recovery factor is increasing from concentration of 0.00002% until 0.0004%. The recovery factor is then decreasing from concentration of 0.0004% until 0.008%. Highest recovery factor is at 0.0004% where the amount of surfactant is fully optimized with injection of CO_2. Low recovery below 0.0004% is due to insufficient surfactant for foam generation which lead to early gas breakthrough along several high permeability. While higher amount of surfactant than 0.0004% is over utilized where most all of gas is formed into foam and no additional gas to push the foam and oil along the reservoir to production well. While in Figure 28 showing increasing recovery with increasing surfactant concentration until 0.0008%, and declining after the point. Lower recovery prior 0.0008% is due to insufficient of surfactant for foam generation. Due to this, the gas can have breakthrough along the layers and reduces the displacement efficiency. A significant decreasing recovery after optimum point for both with asphaltene presence and without asphaltene presence is shown is due to adsorption effect of surfactant to reservoir rock where the adsorbed surfactant will cause pore throat and permeability reduction. The higher surfactant concentration, the higher the amount of surfactant adsorbed into reservoir, hence the lower the recovery. Thus, it is important to determine the optimum surfactant concentration before any FAWAG injection can be implemented.

4.14 COST ESTIMATION OF OPTIMUM SURFACTANT CONCENTRATION

Cost of surfactant = Number of cycles * Days in a cycle * Injection rate * Surfactant concentration * Surfactant Price per Pound

= 12 * 90 day * 696 barrel/day * 0.2784 lb/barrel * $0.9/lb

= $ 188,341

Revenue using surfactant = Cumulative Volume of Oil * Average Oil Price

= 501513 stb * $100/stb

= $ 50,151,380

From the calculation, implementation of FAWAG is a revenue generating project. Nevertheless the calculation need to take account the facilities, preliminary research before implementation and any short-sighted problem which will arise. The calculation is more toward highlighting the advantage of implementing FAWAG injection.

CHAPTER 5

CONCLUSION

1. WAG injection shown a better recovery in reservoir without asphaltene presence reservoir. Lower recovery of WAG in asphaltene presence reservoir is due to clogged pore throat which reduces in WAG efficiency.

2. FAWAG in asphaltene presence reservoir yielded higher recovery compared to FAWAG injection in without asphaltene presence reservoir. The higher recovery by FAWAG with asphaltene is due to improved mobility control.

3. Both FAWAG with and without asphaltene presence shown higher recovery than WAG. The better recovery was because better gas mobility control and effect of changes in oil-water IFT.

4. WAG and FAWAG injection with PV ratio 2:1 yielded better recovery factor in with and without asphaltene-presence reservoir. Injection ratio of water should not be too low which will cause poor displacement efficiency.

5. As concentration of surfactant increasing, the recovery factor increasing until optimum surfactant concentration is reached where highest recovery factor is found. The effect of surfactant concentration is similar toward both with and without asphaltene-presence reservoir. Additional surfactant concentration above optimum point will affect recovery due to adsorption of surfactant into reservoir which will cause reduction of permeability and clogged pore throat.

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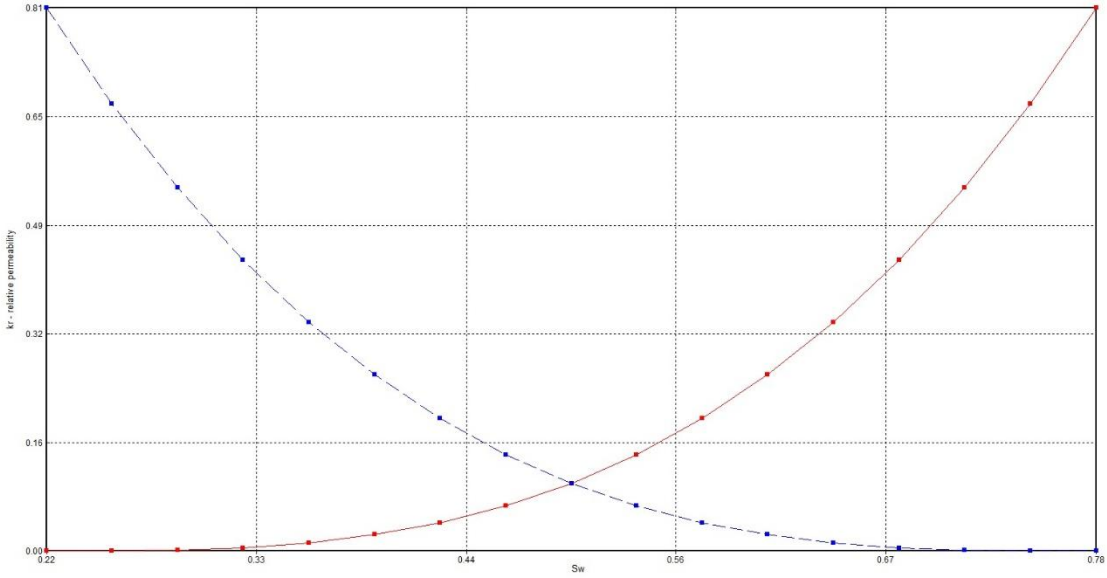
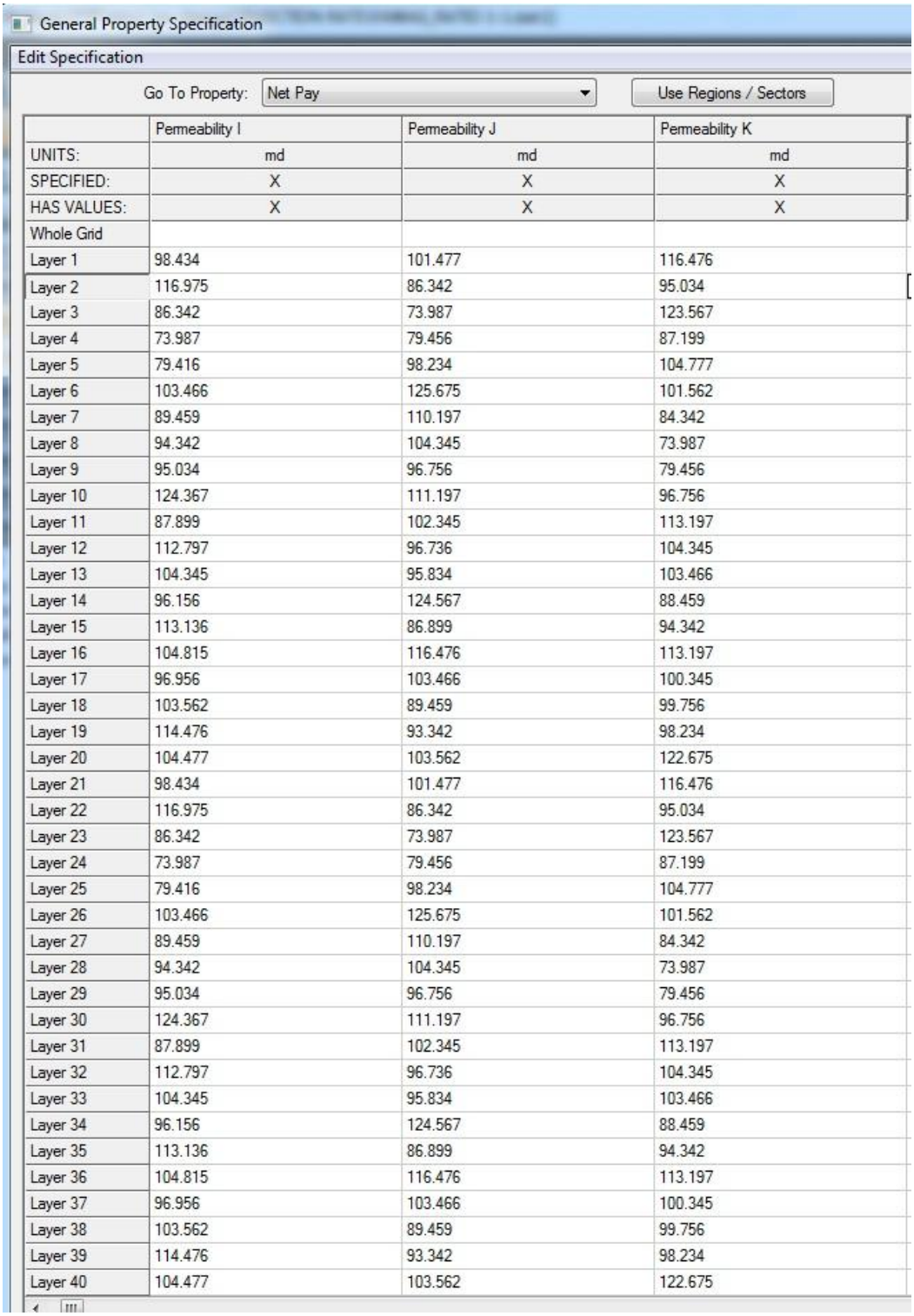
APPENDIXES

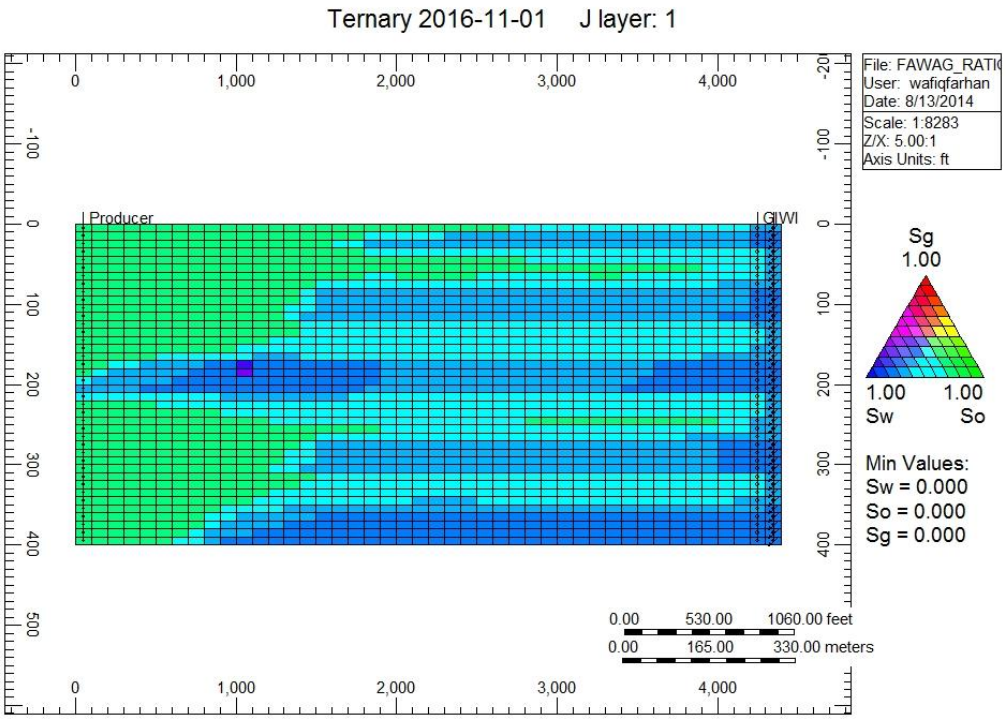


1) Relative permeability

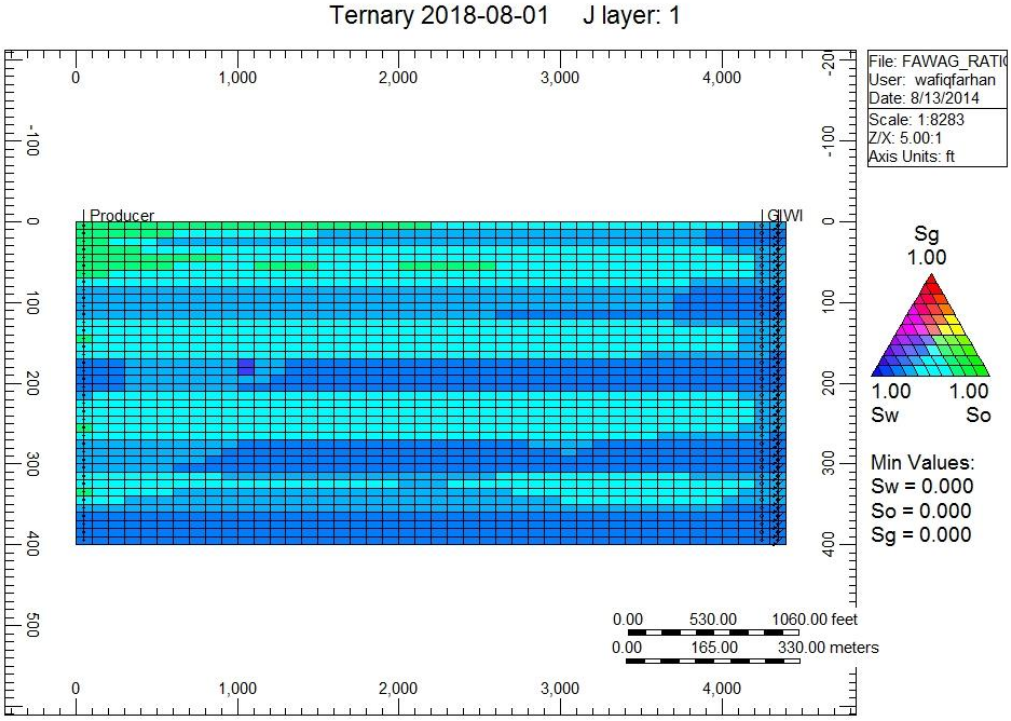


	Permeability I	Permeability J	Permeability K
UNITS:	md	md	md
SPECIFIED:	X	X	X
HAS VALUES:	X	X	X
Whole Grid			
Layer 1	98.434	101.477	116.476
Layer 2	116.975	86.342	95.034
Layer 3	86.342	73.987	123.567
Layer 4	73.987	79.456	87.199
Layer 5	79.416	98.234	104.777
Layer 6	103.466	125.675	101.562
Layer 7	89.459	110.197	84.342
Layer 8	94.342	104.345	73.987
Layer 9	95.034	96.756	79.456
Layer 10	124.367	111.197	96.756
Layer 11	87.899	102.345	113.197
Layer 12	112.797	96.736	104.345
Layer 13	104.345	95.834	103.466
Layer 14	96.156	124.567	88.459
Layer 15	113.136	86.899	94.342
Layer 16	104.815	116.476	113.197
Layer 17	96.956	103.466	100.345
Layer 18	103.562	89.459	99.756
Layer 19	114.476	93.342	98.234
Layer 20	104.477	103.562	122.675
Layer 21	98.434	101.477	116.476
Layer 22	116.975	86.342	95.034
Layer 23	86.342	73.987	123.567
Layer 24	73.987	79.456	87.199
Layer 25	79.416	98.234	104.777
Layer 26	103.466	125.675	101.562
Layer 27	89.459	110.197	84.342
Layer 28	94.342	104.345	73.987
Layer 29	95.034	96.756	79.456
Layer 30	124.367	111.197	96.756
Layer 31	87.899	102.345	113.197
Layer 32	112.797	96.736	104.345
Layer 33	104.345	95.834	103.466
Layer 34	96.156	124.567	88.459
Layer 35	113.136	86.899	94.342
Layer 36	104.815	116.476	113.197
Layer 37	96.956	103.466	100.345
Layer 38	103.562	89.459	99.756
Layer 39	114.476	93.342	98.234
Layer 40	104.477	103.562	122.675

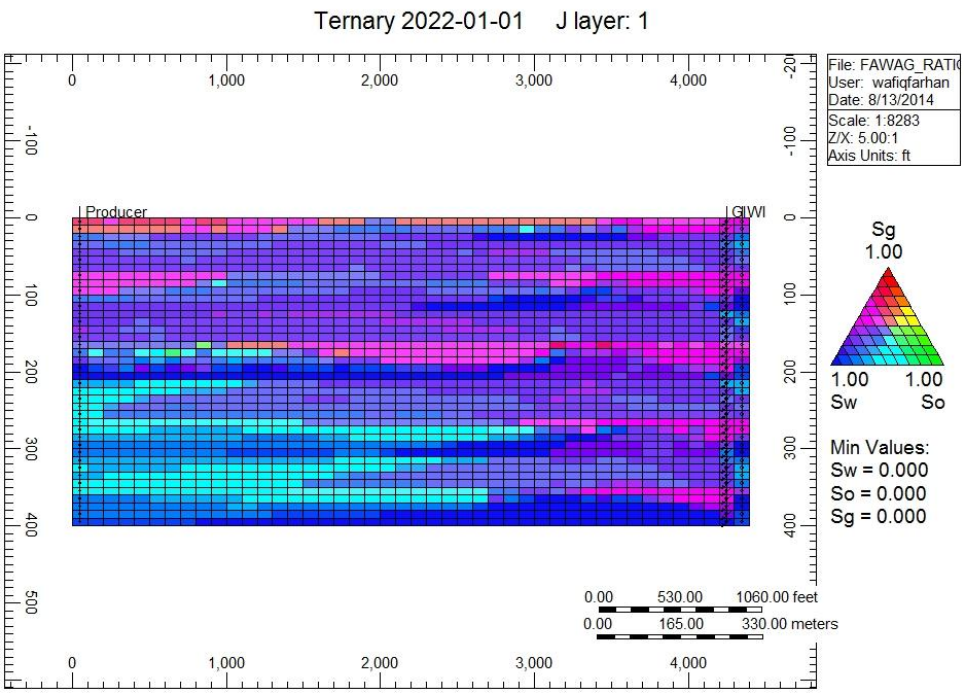
2) Permeability distribution



3) Water breakthrough during waterflooding



4) Water cut reached 80%



5) Foams are blocking the gas from entering high permeability layers